NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow ...Today[sm]

10 Krey Boulevard ♦ Rensselaer, NY 12144

January 12, 2010

ELECTRONICALLY SUBMITTED

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: New York Independent System Operator, Inc.'s Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow; Docket No. ER08-1281-___.

Dear Secretary Bose:

In accordance with paragraph 6 and ordering paragraph "B" of the Federal Energy Regulatory Commission's ("Commission's") July 16, 2009 *Order Authorizing Public Disclosure of Enforcement Staff Report and Directing the Filing Of an Additional Report* in Docket No. ER08-1281-000 ("July Order"),[1] and in accordance with paragraphs 8 and 9 of the Commission's *Order Granting Clarification* that was issued on September 14, 2009 in Docket No. ER09-1281-003,[2] the New York Independent System Operator, Inc. ("NYISO"), hereby submits this *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow* ("Report"). Ordering paragraph "B" of the July Order instructs the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order." Paragraph 9 of the Order Granting Clarification instructs the NYISO to "address, in its 180-day report, *all* solutions to the Lake Erie loop flow problem, including but not limited to: (i) the implementation status of the Ontario-Michigan PARs; (ii) the progress that has been made on the operating agreements for the Ontario-Michigan PARs; and, (iii) the complementary role that physical controls will play in the comprehensive solution to the Lake Erie loop flow problem."

While the NYISO is responsible for submitting this Report to the Commission, it cannot take sole credit for developing (or even drafting) the proposed solutions to Lake Erie loop flow that are described herein. Rather, the contents of this Report, and of the white papers and presentations attached hereto, were developed through collaboration between and among PJM Interconnection, LLC ("PJM Interconnection"), the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), the Ontario Independent Electricity System Operator ("IESO") and the NYISO, with input from the stakeholders of the foregoing ISOs and RTOs. The collective recommendation of the ISOs and RTOs is

[1] *New York Independent System Operator, Inc.*, 128 FERC ¶ 61,049.

[2] *New York Independent System Operator, Inc.*, 128 FERC ¶ 61,239.

to implement a series of market solutions, including: (a) Buy-Through of Congestion, (b) Congestion Management/Market-to-Market Coordination, (c) Interface Pricing Revisions, and (d) Interregional Transaction Coordination. These proposed market solutions are described in Section II of this Report. In addition to the proposed market solutions, IESO and the Midwest ISO are pursuing the implementation of Phase Angle Regulator ("PAR") devices on the free flowing ties between Ontario and Michigan. The possible operation of the PARs at the Ontario-Michigan border to better align actual power flows to schedules, along with other efforts to coordinate the use of physical controls within the four ISO/RTO region, is addressed in Section III of this Report.

As described in Section VII of this Report, the NYISO is working to implement several aspects of the Broader Regional Market solutions proposed in this Report with ISO New England Inc. ("ISO-NE"). As explained in Section VIII of this Report, Hydro Quebec TransEnergie has volunteered to work with the NYISO to pioneer the NYISO's initial implementation of the proposed Interregional Transaction Coordination solution, whereby the scheduling of real-time transactions between neighboring markets will occur on a more frequent (quarter hour or five minute) basis.

The NYISO would like to take this opportunity to thank the participating ISOs and RTOs, their Boards of Directors[3] and their stakeholders for complying with both the letter and spirit of the Commission's encouragement that "all interested parties … pursue a constructive, workable consensus addressing these matters as expeditiously as possible."[4] The identification of a comprehensive set of market solutions in this Report would not have been possible if entities like PJM Interconnection, the Midwest ISO and IESO had not each shouldered a significant share of the burden.

The NYISO hopes and expects that the cooperative effort that has permitted the ISOs and RTOs to expeditiously develop the Broader Regional Market solutions that are described in this Report and detailed in the white papers that are attached hereto, will continue until all of the solutions described in this report have been fully implemented. As explained in Section VI of this Report, the ISOs and RTOs expect to begin implementing the first of the proposed market solutions in 2010, but do not expect some solutions to be in place until 2012, or later. The proposed implementation schedule should provide adequate time to address the details of implementing each of the proposed solutions, and also allows further opportunities for stakeholder review of and input regarding the proposed solutions.

[3] The Boards of Directors of the various ISOs and RTOs have taken an active interest in ensuring the timely development of effective solutions to Lake Erie loop flow.

[4] July Order at P. 6.

I. Documents Submitted

1. Broader Regional Markets, Long Term Solutions to Loop Flow white paper prepared by Midwest ISO, PJM Interconnection, IESO and NYISO ("Attachment A")[5];

2. Broader Regional Markets, Developing Solutions to Lake Erie Loop Flow, presentations prepared by IESO, Midwest ISO, PJM Interconnection and NYISO that were presented to stakeholders of the four ISOs/RTOs at a technical conference held on December 15, 2009 in Carmel, Indiana ("Attachment B");

3. Broader Regional Markets, Solutions to Loop Flow presentations prepared by IESO, Midwest ISO, PJM Interconnection and NYISO that were presented to stakeholders of the four ISOs/RTOs at a technical conference held on October 29, 2009 in Albany, New York ("Attachment C");

4. Overview of Proposed Inter-Area Coordination Between ISO New England and New York ISO ("Attachment D");

5. Letter from Mr. Thomas H. Wrenbeck of ITC Holdings to Mr. Rana Mukerji of the NYISO dated December 23, 2009 ("Attachment E"); and

6. *Northeast ISO Seams Resolution Report for the third quarter of 2009, issued October 19, 2009 ("Attachment F").

*The NYISO has attached the Northeast ISO Seams Resolution Report for the third quarter of 2009 ("Seams Report") to this Report in order to make clear that the Broader Regional Market solutions proposed in this report are neither expected, nor intended to comprehensively resolve all existing coordination or seams issues between the participating ISOs and RTOs. Opportunities for enhanced coordination that are not addressed by the Broader Regional Markets solutions proposed in this Report are identified in the Seams Report.

[5] Attachment A is the latest draft of a white paper that describes the proposed Broader Regional Market solutions to Lake Erie loop flow in far greater detail than this Report. Earlier versions of the white paper were distributed for discussion at the October 29, 2009 technical conference in Albany, New York and the December 15, 2009 technical conference in Carmel, Indiana. The attached version addresses/responds to many stakeholder concerns that were raised at the technical conferences. For example, provisions adding payments/credits for the scheduling of transactions that relieve transmission congestion were added to page 27 of the white paper based on stakeholder input.

II. Summary of Proposed Broader Regional Market Solutions

A. Introduction

The ISOs and RTOs have developed four Broader Regional Market solutions. A prerequisite to implementing the Buy-Through Congestion and Congestion Management/Market-to-Market Coordination solutions is the completion of the North American Electric Reliability Corporation's ("NERC's") Parallel Flow Visualization tool (or the development of an alternative thereto), which will significantly improve the ability to accurately perform generation-to-load calculations and will make available common and consistent information regarding the sources of power flows and their impacts.[6] The proposed Buy-Through of Congestion solution is designed to address loop flow by allocating a more complete and accurate measure of the costs caused by external transactions, such as imports, exports and wheels-through, to the cost-causing transactions. The proposed Interface Pricing Revisions address existing seams between markets that tend to exacerbate loop flows. The Congestion Management solution (referred to as "Market-to-Market Coordination") is expected to reduce the cost of addressing transmission congestion within the region, and can be utilized in conjunction with Buy-Through of Congestion to minimize the cost of addressing flowgate constraints. Enhanced Interregional Transaction Coordination will reduce the risk/exposure to congestion costs experienced by entities that schedule inter-Balancing Authority transactions, and is expected to provide other financial benefits to participating markets. Each of the ISOs and RTOs intends to cover its own costs of designing and implementing the Broader Regional Market solutions proposed in this Report.

A long-term solution to Lake Erie circulation can best be achieved by the collective implementation of all of the proposed initiatives. Individually, each initiative only addresses a component of the Lake-Erie loop flow problem, and provides limited benefits in terms of improved market efficiency. Implemented as a group, the proposed solutions are expected to produce far greater benefits. For example, Buy-Through of Congestion addresses the scheduling of external transactions, but does not address the beneficial or detrimental impact that scheduling a particular mix of generation to serve Balancing Authority load may have on a neighboring market. Congestion Management fills this gap by permitting a Balancing Authority to schedule its generation in a manner that will result in the lowest overall regional cost to resolve system constraints. Interregional Transaction Coordination allows for more frequent region-to-region interchange which will improve the efficacy and responsiveness of both the Buy-Through of Congestion and Congestion Management solutions. The combined capabilities of the proposed solutions offer the potential to reduce uplift costs associated with real-time event management and congestion management, to improve the capability to incorporate intermittent resources, and to lower total system operating costs.

A summary explanation of the Parallel Flow Visualization Tool and of each of the four proposed Broader Regional Market solutions is set forth below. A significantly more detailed description of each

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[6] The Parallel Flow Visualization Tool, or a comparable alternative, is needed to provide the NYISO with the information it needs to support implementation of the Market-to-Market Coordination and Buy-Through of Congestion solutions that are described in this Report.

of the items described below is available in Attachment A to this Report. Attachment A is the latest version of a white paper that was prepared by the ISOs and RTOs and distributed to stakeholders for comment and discussion at technical conferences that were held on October 29, 2009 in Albany, New York, and on December 15, 2009 in Carmel, Indiana.

B. Parallel Flow Visualization Tool

Network flows on an interconnected grid are the composite result of all the individual actions taken in the interconnected regions to dispatch generation to meet their load, to direct flow on controllable facilities, and to transfer energy between regions. No single region currently has access to sufficient information to decompose line and flowgate flows into the unique sources of those flows.

The Parallel Flow Visualization Tool will assemble the necessary real-time data to perform the generation-to-load calculations, facilitate the calculation of impacts and make available common and consistent information regarding the sources of power flows and their impacts to all regions. The Parallel Flow Visualization Tool will distinguish the source of flow between (a) each separate region's impacts associated with generation-to-load dispatch and (b) individual transaction impacts.

The NERC Interchange Distribution Calculator ("IDC") Working Group is currently tasked with defining the necessary data reporting requirements and developing with Open Access Technologies, Inc. ("OATI") the specification for performing a generation-to-load calculation, which is referred to as a "market flow" calculation when applied to Balancing Authorities that operate in organized ISO/RTO markets. Accurate and timely data reporting by Balancing Authorities will be required to support the accurate computation of market flows.

The future market flow calculation process will require some entities to provide significantly more data, and on a more frequent basis than is currently supported. The magnitude of the expected benefits will be directly tied to the quality of the data reporting. The ISOs and RTOs support the accurate, complete and timely reporting of the necessary information to achieve the region wide implementation of the parallel flow visualization process and the visibility it provides to market flow impacts. The information that will be provided by the Parallel Flow Visualization Tool is required to support the NYISO's implementations of Congestion Management and Buy-Through of Congestion Broader Regional Market solutions to Lake Erie loop flow, and will augment the information available in the IDC (and available for the NERC Transmission Loading Relief "TLR" procedures) to address impacts from Lake Erie loop flows.

If NERC, or OATI, is unable to (timely) develop the Parallel Flow Visualization Tool, alternative solutions will need to be developed to obtain the information that is necessary to implement the Congestion Management and Buy-Through of Congestion Broader Regional Market solutions. To support the ISOs and RTOs efforts to timely implement the Broader Regional Market solutions, the ISOs and RTOs will evaluate by June 1, 2010 the state of the Parallel Flow Visualization Tool implementation. If the solution is determined to be abandoned, unsupportable, or not achievable in 2010, the ISOs and RTOs will pursue alternative solutions to the visibility initiative in an effort to maintain the proposed solutions implementation timelines.

C. Buy-Through of Congestion

1. Explanation of Solution

The current practice for scheduling of interregional transactions only requires scheduling parties to pay for the congestion charges assessed by the Balancing Authorities that are part of the "contract path" over which an external transaction is scheduled. Costs that an external transaction imposes on Balancing Authorities that are not included in the contract path are not currently considered in the scheduling process, nor are they charged to the scheduling entity. Buy-Through of Congestion addresses this shortcoming by more completely assessing the congestion charges associated with scheduling an interregional transaction to the scheduling entity.

The movement of power from Balancing Authority to Balancing Authority is typically scheduled on a particular contract path. In reality, power moves consistent with the laws of physics and the relative impedances of the various elements of the transmission system, and actual power flows can be quite different from the path over which a particular transaction is scheduled to flow.

Managing power that flows in a manner that is not consistent with the contract path over which an external transaction is scheduled to flow can be a costly endeavor, particularly when the associated uncontrolled off-contract path loop flow causes congestion on prime transmission corridors in Balancing Authorities that do not have the transaction scheduled in their markets. The NERC TLR procedures provide a blunt instrument for addressing the off-contract path impacts of scheduled transactions. Invoking the TLR procedures may result in market and operational inefficiencies because TLR requires the curtailment of expected energy deliveries without regard to economic rationing principles. The TLR process does not take into account the scheduling party's possible economic willingness to pay to maintain its transaction schedules, nor does the TLR process account for or assess the economic benefit of moving power between regions. More efficient utilization of the transmission network can be achieved and more accurate transaction scheduling decisions can be made if the cost of managing off-contract path congestion can be calculated and appropriately allocated to the scheduled power transfers that caused the congestion. The proposed Buy-Through of Congestion Broader Regional Market solution will assign off-contract path power flows comparable congestion cost exposure for equivalent use of the transmission network to contract path power flows.

The Buy-Through of Congestion bidding features will allow the scheduling party to indicate if it is, or is not, willing to pay the congestion charges caused by its transactions off-contract path flow impacts. If a transaction party indicates it is not willing to pay congestion charges its transaction will be removed if the off-contract path flows created by the transaction add to congestion costs in a participating off-contract path ISO or RTO. Once removed, the transaction will not be reinstated until the neighboring ISO/RTO indicates that the congestion on the impacted flowgate has been adequately relieved. Transactions that indicate they are not willing to pay congestion charges in their bid will not incur such charges for the period of time necessary to remove the transactions after congestion is identified.

The objective of the Buy-Through of Congestion Broader Regional Market solution is to (a) identify the sources of loop flow caused by Balancing Authority to Balancing Authority schedules via the NERC IDC Parallel Flow Visualization Tool, (b) determine the costs incurred in supporting the loop flows by each impacted region, as indicated by the actual real-time shadow cost of each constrained flowgate, or the equivalent, and (c) allocate the costs incurred by the off-contract path Balancing Authorities to the scheduling entity, or remove the associated schedules if the scheduling entity is not willing to pay the full cost of flowing its transaction(s). The Buy-Through of Congestion processes will result in a more complete identification of and accurate assignment of the costs to move power between regions, and will provide an economic alternative to the administrative/physical TLR curtailment processes. IESO, Midwest ISO, PJM Interconnection and NYISO all plan to participate in developing and implementing the Buy-Through of Congestion Broader Regional Market solution, subject to obtaining the necessary approvals.

Even after the Buy-Through of Congestion process is implemented, TLR will remain available as a reliability backstop to address circumstances where the proposed Buy-Through of Congestion solution is not able to provide timely, or does not provide sufficient constraint relief to protect system reliability. For example, this could occur when a Balancing Authority’s internal re-dispatch cannot achieve the needed relief.

2. Expected Benefits

The Buy-Through of Congestion Broader Regional Market solution will provide more accurate price signals because it requires scheduling entities to pay, and permit off-contract path Balancing Authorities to recover, the congestion cost associated with scheduling an external transaction (import, export or wheel-through). The solution also provides an economic alternative to the market and operational interruptions that occur when the TLR process is invoked. Both of these benefits will result in more efficient utilization of the transmission network.

3. Stakeholder Concerns

In discussions with stakeholders, the Buy-Through of Congestion solution has been the most controversial of the Broader Regional Market solutions proposed by the ISOs and RTOs. However, from the ISO’s and RTO’s perspective, it is an important solution because it is the solution that will ensure that entities scheduling energy transactions around Lake Erie pay the true cost of achieving their transaction energy schedule, including the congestion/redispatch costs incurred by off-contract path markets that are necessary to permit the scheduled transaction to be delivered.

Stakeholder concerns have focused in two areas. First, stakeholders have expressed a desire that they be able to submit, as a component of an external transaction bid, an indication of the total amount of congestion they are willing to pay to off-contract path Balancing Authorities before the transaction must be removed (an “up to” congestion bid). Second, stakeholders have taken the position that purchasing “firm” transmission service over a transaction’s contract path should either excuse the firm transaction from paying the costs of congestion caused in off-contract path markets, or should require the removal of all non-firm transactions before firm transactions can be assessed congestion charges for their impact on off-contract path markets. Both of these concerns are briefly addressed below. However, the ISOs and RTOs expect to take up and thoroughly vet these issues as part of the implementation and stakeholder review processes that are described in Section V.C of this Report.

Several stakeholders have requested that the Buy-Through of Congestion solution include the ability to specify a real-time "up-to" congestion charge limitation, indicating the maximum amount of off-contract path congestion the entity scheduling a transaction would be willing to pay. The ISOs and RTOs recognize that Buy-Through of Congestion will (appropriately) result in cost risk exposure being transferred from each regions internal loads (which are currently responsible for uncollected congestion charges) to the transacting parties whose schedules produce the off-contract path congestion. The ISOs and RTOs are committed to providing the necessary data transparency and visibility of projected and occurring congestion costs to allow traders to consider their cost exposure when requesting a schedule or alternatively to terminate their schedules upon observations of congestion charge allocations. The ISO's additionally acknowledge the need to develop the necessary congestion cost hedging products to allow traders to purchase the congestion management product at specified values within the respective day-ahead markets, where applicable. Past experience has not shown the need for an up-to congestion product to be necessary if there is adequate real-time price transparency around price differences. The ISOs and RTOs response to the desire expressed by stakeholders to incorporate up to congestion bids in the Buy-Through of Congestion Broader Regional Market solution is addressed in greater detail on pages 17 – 20 of the white paper that is included as Attachment A to this Report, and in the presentation titled *Management of Congestion Cost Exposure* that is included in Attachment B to this Report.

Stakeholders have also expressed concern that scheduling "firm" transmission service along the contract path will not protect an external transaction schedule if the scheduling entity does not elect to pay for the congestion its transaction may cause in Balancing Authority areas that are not included in the external transaction's contract path. In fact, it is possible that a firm transaction that is not willing to pay off-contract path congestion could be removed before an otherwise identical non-firm transaction that elects to pay off-contract path congestion *if* both transactions are determined to be causing congestion that requires redispatch by an off-contract path Balancing Authority.

Transactions scheduled using firm transmission service are responsible for their congestion impact along the contract path. The scheduling of transmission service is separate and distinct from the responsibility for paying congestion charges, and is not equivalent to ensuring a congestion cost-free path of transmission access. Transacting parties, regardless of service provisions, must still supply bids and offer and be evaluated and selected in economic merit order.

In some markets the cost of firm service may include a hedging product to protect against potential congestion charges. Hedges against congestion costs can also/alternatively be acquired through the available supplemental Financial Transmission Right or Transmission Congestion Contract auctions. The cost of the available hedging products is, effectively a proxy for the potential congestion cost exposure. Hedging mechanisms are limited in their scope to the market from which they are procured. To the extent that service is necessary across multiple regions, multiple products may need to be acquired.

While the costs of parallel flow impacts have not been historically allocated to external transaction schedules,[7] that outcome was not based upon the expectation that the costs incurred by off-contract path Balancing Authorities were not the responsibility of the scheduling party.[8] Rather, the problem was that it was not technically feasible to accurately assign parallel flow impacts to a particular transaction. Congestion costs could not be applied to off-contract path impacts until the evolution of the individual marketplaces achieved the ability to identify and quantify the costs of these impacts and the collective marketplaces achieved a solution that would allow for the application of these charges to the sources. The Parallel Flow Visualization Tool and Buy-Through of Congestion solution will enable the ISOs and RTOs to accurately identify, assign and apply congestion charges to off-contract path flows, thereby comparably charging external transactions for their contract path and off-contract path congestion impacts. All transmission customers will have the opportunity to indicate their willingness (or unwillingness) to be responsible for these congestion charges. Removing a transaction schedule because the scheduling entity has taken an economic position that is no longer viable is a scheduling decision made by the participant. It is not a violation of the firm transmission service arrangement if the customer decides that it is unwilling to pay for redispatch service in off-contract path markets where its transaction has a congestion impact.

D. Congestion Management/Market-to-Market Coordination

In paragraph 6 of the July Order, the Commission instructed the NYISO to address Congestion Management in this Report. PJM Interconnection, the Midwest ISO and the NYISO have agreed to work together to implement Congestion Management (called Market-to-Market Coordination) at their borders. The proposed implementation timeline is coincident with the proposed implementation timeline for Buy-Through of Congestion. A summary description of the proposed solution is set forth below. Please see pages 28 to 36 of the white paper that is included as Attachment A to this Report for additional details explaining how Market-to-Market Coordination is expected to operate.

A highly interconnected transmission network provides benefits of improved operational reliability and redundancy. However, a necessary byproduct of synchronously interconnected Balancing Authorities are loop flows resulting from a regions dispatch of its resources to meet its own load requirements. While loop flows can cause or aggravate constraints in a neighboring Balancing Authority, the synchronous interconnection of neighboring markets also presents the opportunity for multiple Balancing Authorities to act to relieve transmission congestion on the interconnected system.

The re-dispatch of generators within a Balancing Authority that is interconnected with the Balancing Authority that is experiencing the congestion may be able to address transmission constraints more cost effectively than the re-dispatch of generators or other control action taken by the congested Balancing Authority. A Congestion Management, or Market-to-Market Coordination, protocol

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[7] To date, the only remedy that has been available to address flowgate impacts from off-contract path flows has been the NERC TLR process.

[8] The *pro forma* tariffs provide that redispatch service will be provided to make firm transmission service available, assuming that the transmission customer is willing to pay for the cost of redistpatch.

(1) allows for inter-Balancing Authority dispatch to manage congestion if, and to the extent, an interconnected Balancing Authority can re-dispatch resources to alleviate the congestion at a lower cost than the Balancing Authority that is experiencing the congestion, and (2) permits the appropriate settlement (payment) based on the facts and circumstances of each situation.

In order to effectively implement Market-to-Market Coordination it is necessary to (a) pre-identify a consistent set of constraints that multiple Balancing Authorities can address through re-dispatch actions, (b) develop an agreed to baseline of allowable usage of each others transmission networks,[9] and (c) establish data sharing protocols to communicate real-time constraint management costs between Balancing Authorities. After-the-fact calculation of settlement charges will be performed to provide compensation for the dispatch action when the system flows are less than pre-defined baseline values. Overuse of a neighboring Balancing Authority's transmission system that results in costs to the neighboring Balancing Authority must be redressed. Market-to-Market Coordination will be incorporated directly into a regions dispatch and price setting protocols to maintain the existing consistency between resource schedules and prices. No other explicit charge or refund to a redispatched resource will be necessary.

Expected benefits of implementing the Market-to-Market Coordination solution include:

- Lower congestion costs. The ability to use lower cost resources in an interconnected Balancing Authority to address transmission constraints is expected to reduce the overall cost of managing transmission congestion.
- More consistent pricing across ISO/RTO borders. When Market-to-Market Coordination is in effect, prices at the borders between Balancing Authorities are expected to converge more closely. For example, under Market-to-Market Coordination, a resource located in PJM could be setting the price, or determining the shadow cost of relieving a New York transmission constraint (or *vice-versa*).
- More reliable operation. Because economic generation in another RTO/ISO is now available to address transmission constraints (a broader pool of resources is available), the participating markets should experience fewer emergency transmission operations.

As explained above, Market-to-Market Coordination can achieve a more cost effective utilization of the region's collective assets to address constraints across multiple systems, resulting in lower overall congestion costs to consumers and provides a more consistent price profile across markets. The Market-to-Market Coordination details currently being considered are largely based on the existing Market-to-Market coordination program that is currently in place between the Midwest ISO and PJM Interconnection, a program with which the Commission and stakeholders are already familiar.

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[9] PJM Interconnection and the NYISO have spent significant time discussing how best to determine appropriate rules for determining baseline "entitlements" to use the capacity of a neighboring transmission system. Various alternatives have been considered which require a representative set of historical flowgate impacts to properly evaluate. The ISOs and RTOs are awaiting the completion of the Parallel Flow Visualization tool to assemble the necessary data set of cross-border flowgate impacts to complete their benchmarking analysis. The ISOs and RTOs await the opportunity to work together using the information that the Parallel Flow Visualization Tool will produce.

E. Interface Pricing Revisions

In paragraph 6 of the July Order, the Commission instructed the NYISO to address Interface Pricing in this Report. The Midwest ISO, PJM Interconnection and the NYISO have agreed to implement comparable interface pricing methods at their common borders. IESO is still in the process of determining its intended participation in the measure described below.

Efficient and compatible interface proxy bus prices will improve the interconnected markets' ability to efficiently transfer power within the four ISO/RTO region. Potential improvements to interface pricing methods have been identified both (1) at times when there is no, or limited ability to conform actual power flows around Lake Erie to scheduled power flows, and (2) at times when Phase Angle Regulators ("PARs") and other control devices are able to conform actual power flows to scheduled power flows within reasonable tolerances. In recognition of the overall objective of harmonizing market rules across the region, the NYISO proposes to pursue modifications to its interface pricing method that will apply at times when actual power flows are not consistent with scheduled power flows. Under these circumstances, the NYISO intends to propose adjustments to its external proxy bus pricing to:

- Recognize the incremental distribution of power flows around Lake Erie when evaluating and pricing the marginal impacts of transaction and generation schedules;
- Evaluate the need for, and scheduling rules surrounding, establishing an additional proxy bus location for the Midwest ISO to acknowledge power deliveries from or to the Midwest region; and
- Evaluate the continued applicability of the existing circuitous path prohibitions.[10]

The ISOs and RTOs also recognize the importance of maintaining compatible and efficient interface proxy bus prices when the PARs at the Ontario – Michigan border are ultimately installed and available to mitigate Lake Erie loop flows. These devices are expected to have the ability to adjust actual power deliveries to be more consistent with scheduled power deliveries. Existing interface proxy bus pricing methods may not set accurate prices under all operating scenarios and may require (a) additional pricing points to be created, or (b) the interface price weighting associated with current points to be adjusted, or (c) adjustments to incremental distribution of power flows to acknowledge power flows that are substantially consistent with the contract path of a transaction.

All of the participating ISOs/RTOs interface proxy pricing methods will need to be able to account for the ability of PARs to manage Lake Erie loop flows.

- At times when actual power flows are consistent with scheduled power flows, the pricing method used will treat power as flowing consistent with the contract path.

[10] The NYISO does not plan to seek permission from its stakeholders to remove the circuitous path scheduling prohibition from its Tariffs until actual experience with the physical and market solutions described in this Report show that the prohibition is no longer necessary or appropriate. When the proposed physical and market solutions prove their efficacy in practice, the NYISO will discuss removing the existing eight-path circuitous scheduling prohibition with its stakeholders.

- At times when actual power flows do not conform to scheduled power flows (at times when there is loop flow), the interface proxy pricing methods will need to reflect the path over which power is actually flowing, which will not be entirely consistent with the contract path.

In implementing the methods described above, the ISOs and RTOs will also need to evaluate their ability to predict when the PARs will/will not be able to conform power flows to schedules around Lake Erie, and to incorporate the necessary assumptions into each ISO/RTO's respective day-ahead and hour-ahead markets.

F. Enhanced Interregional Transaction Coordination

Today, PJM Interconnection and the Midwest ISO provide the ability for market participants to schedule an energy transaction on a fifteen minute basis on external interfaces. Enhanced Interregional Transaction Coordination will permit the scheduling of inter-Balancing Authority transactions involving the NYISO on a more frequent basis than the current hourly schedules. Flexible transaction scheduling provisions improve market and operational efficiency by allowing resources schedules to adjust to the dynamic changes in system conditions, as well as unexpected changes to projected conditions. Desired additional flexibility must be balanced with the operational benefits associated with defined firm energy delivery schedules.

Flexible transaction scheduling requires advancements to the existing processes for the development of transaction schedules and the protocols for validation of those schedules. The existing process lacks the coordination and automation necessary to support a scheduling frequency sufficient to address dynamic system conditions. Transaction schedules must be co-developed, rather than independently evaluated, to ensure both regions arrive at the same outcome and the same expectations for energy delivery or receipt.

Enhanced Interregional Transaction Coordination is expected to lower total system operating costs through improved consistency of transaction schedules with market-to-market prices, to expand the pool of flexible assets that are available to balance intermittent power resources, to improve price consistency and transmission utilization and to address existing uncertainties in forward looking scheduling horizons. As explained above, it will also serve to limit the risk an entity will face when it agrees to pay for the congestion its external transaction causes in off-contract path Balancing Authorities because it will be possible to withdraw an accepted transaction should a dramatic intra-hour price change occur in an off-contract path market.

As indicated in Section VI of this Report, the NYISO anticipates implementing the Enhanced Interregional Transaction Coordination Broader Regional Market solution with PJM Interconnection on the Neptune and Linden VFT Scheduled Lines, followed closely by the broader NYISO/PJM Interconnection interface, in 2011.

III. Implementation and Effective Operation of Phase Angle Regulators to Control Loop Flows

Paragraph 9 of the Order Granting Clarification instructs the NYISO to "address, in its 180-day report, *all* solutions to the Lake Erie loop flow problem, including but not limited to: (i) the implementation status of the Ontario-Michigan PARs; (ii) the progress that has been made on the operating agreements for the Ontario-Michigan PARs; and, (iii) the complementary role that physical controls will play in the comprehensive solution to the Lake Erie loop flow problem." This Report addresses each of the issues identified in the Commission's Order below. The Report also addresses the ISOs and RTOs plan to perform a study that is ultimately expected to result in the drafting and implementation of regional PAR operating guidelines.

A. Implementation Status of the Ontario-Michigan PARs

There is protective relay work being completed in Ontario that is necessary for the effective operation of the Ontario-Michigan PARs. This work is expected to be completed by the end of the first quarter of 2010. At that time it is expected that all of the Ontario-Michigan PARs will be available to provide service. *See* Attachment E.

B. Operating Agreement for the Ontario-Michigan PARs

The NYISO has been informed by a representative of International Transmission Company d/b/a ITC*Transmission* ("ITC") that, although the various necessary operating agreements for the Ontario-Michigan PARs are in "final form," ITC will not execute them and "the Department of Energy will, accordingly, not be in a position to approve the pending amendment to ITC's Presidential Permit which is required to place the PARs into service" until consumers in the other markets surrounding Lake Erie agree to pay for a portion of the claimed $8 million annual cost ITC charges its consumers for constructing, operating and maintaining its PARs at the Ontario-Michigan border. *See* Attachment E.

C. Complimentary Role of Physical Controls in Developing Comprehensive Solution to Lake Erie Loop Flow

1. Price Setting

As explained in Section II.E of this Report, at times when the coordinated operation of the PARs around Lake Erie is able to conform actual power flows to scheduled power flows within mutually agreed upon tolerances, the interface pricing method used by the ISOs and RTOs will treat power as flowing consistent with the contract path. At times when the actual power flows do not conform to scheduled power flows (at times when there is loop flow), the ISOs and RTOs interface proxy pricing methods will need to reflect the path over which power is actually flowing.

2. Anticipated Interaction with TLR Process

At times when the coordinated operation of the PARs around Lake Erie is able to conform actual power flows to scheduled power flows within mutually agreed upon tolerances, the NERC IDC tool will recognize the delivery of transactions into and out of Ontario on contract path and will not identify external transactions as the source of parallel flows. At times when the actual power flows do not conform to scheduled power flows (at times when there is loop flow), the NERC IDC tools will identify external transaction as having parallel path impacts on flowgates based upon the current physical network configuration.[11]

3. Regional Study and Development of Regional PAR Operating Guide

The operation of the PARs by the four markets around Lake Erie can influence the amount of circulation flows. PARs can be used to alter power flows to follow a different electrical path or to better follow the contract path, consistent with the planned operation of the Ontario-Michigan PARs. While PARs are capable of substantially mitigating/controlling loop flows, they are not capable of eliminating Lake Erie loop flows entirely. Coordinated operation of the PARs in the four markets around Lake Erie can enhance the degree to which circulation flows are managed and avert instances where regional PARs could work at cross-purposes. To this end, a regional study will be initiated during 2010 to identify PARs and other controllable devices that are capable of influencing Lake Erie loop flows and to study the potential reliability and market impacts of better coordinated operation. This study will also identify significant regional paths or flowgates impacted by Lake Erie loop flows.

Upon completion of the analysis and necessary updates to the existing Commission-accepted PAR operating protocols, regional operating guide recommendations will be developed and implemented by the ISOs and RTOs to better manage Lake Erie loop flow through the coordinated operation of the identified significant controllable devices. This effort will include implementing the necessary communications infrastructure and regional business processes to facilitate regional coordination of the identified controllable devices.

D. Cost Allocation

In a letter that is included as Attachment E to this Report, ITC, a member of the Midwest ISO, states its desire to recover an unspecified portion of its estimated $8 million annual cost of owning, operating and maintaining its Ontario-Michigan PARs from consumers across the broader region. In its letter ITC states that, although its Ontario-Michigan PARs will be ready to enter service by the end of the first quarter of 2010, and although agreements for the operation of the PARs are in “final form,” ITC will not execute the agreements that are necessary to permit its Ontario-Michigan PARs to enter service until “substantially more progress is made on the cost sharing issue.” In written comments that ITC

[11] Because transactions that are scheduled across the IESO/Midwest ISO interface will not be identified for curtailment pursuant to the TLR process for off-contract path flowgate impacts at times when the Ontario-Michigan PARs are treated as “controlling” it is vitally important to ensure that the calculation of Lake Erie loop flows that is used for TLR purposes is consistent with and accurately reflect actual system conditions.

submitted to the ISOs and RTOs following the October 29, 2009 technical conference, ITC invited other entities that own/operate PARs and other controllable devices that can be used to mitigate Lake Erie circulation to participate in a plan whereby the cost of these devices would be recovered from the broader region and offered to host a meeting to discuss its proposal.[12]

The NYISO declines ITC's invitation to schedule discussions to determine whether consumers in other markets are willing to pay for a portion of the cost of ITC's Ontario-Michigan PARs. Based on the discussions the NYISO has held with its stakeholders to date, there is no reason for the NYISO to meet with ITC to discuss an agreement to pay for a portion of ITC's costs of owning, operating and maintaining its Ontario-Michigan PARs.[13] The opposition of the NYISO and its stakeholders to ITC's proposal to reallocate the cost of existing transmission facilities that were not developed pursuant to a Commission approved regional planning effort is consistent with the Commission's decisions regarding the allocation of transmission costs within the Midwest ISO and PJM Interconnection.[14]

IV. Tariff Revisions Needed to Support Implementation of Proposed Broader Regional Market Solutions to Lake Erie Loop Flow

Stakeholder and regulatory approvals of the tariff revisions described below will be necessary to implement the proposed Broader Regional Market solutions to Lake Erie loop flow.

A. Parallel Flow Visualization Tool

Possible concerns related to data sharing before the Parallel Flow Visualization Tool is actually being used to direct coordinated regional operation exist. Clarification by the Commission that "Transmission System Information"[15] includes within its scope information that must be shared in order

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[12] *See Comments of International Transmission Company d/b/a ITCTransmission on Draft Loop Flow Report*. Available at:

http://www.midwestiso.org/publish/Folder/4dfde8_124a04ca493_-7c8e0a48324a

[13] Given the circumstances that led to the development of the Ontario-Michigan PARs, all of the New York stakeholders that have expressed a position to the NYISO have indicated that they do not support the regional allocation of the cost of ITC's Ontario-Michigan PARs. This group includes, but is not limited to, the New York Transmission Owners, the Long Island Power Authority and the New York Power Authority.

[14] *See American Electric Power Service Corporation v. Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., et al.* 122 FERC ¶ 61,083 at PP. 95 - 102 (2008).

[15] Transmission System Information, or "TSI" is defined in Section 4.0 of the NYISO's Code of Conduct, which is set forth in Attachment F to the NYISO's Open Access Transmission Tariff.

> TSI is information: (1) that is commercially valuable and (2) access to which is necessary to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Service. Examples of TSI include, but are not limited to, the following:
>
> • Available Transfer Capability;
> • Total Transfer Capability;
> • Information regarding physical Curtailments and Interruptions;
> • Information regarding Ancillary Services;
> • Pricing for Transmission Service; and

to design new systems that will be used to buy, sell or schedule energy and transmission service, could speed the Parallel Flow Visualization Tool development process.

B. Regional PAR Coordination

Modifications to existing Commission-accepted PAR operating agreements may be necessary. Depending upon the nature of the regional PAR operating guideline that is ultimately produced, Commission acceptance of this guideline may also be necessary.

C. Interface Pricing Revisions

The NYISO may have to make changes to its Market Administration and Control Area Services Tariff ("Services Tariff") and/or Attachment B to its Services Tariff and Attachment J to its Open Access Transmission Tariff ("OATT") to explain how and when each of the proposed methods of determining prices at external proxy buses will apply. If the NYISO determines that it needs to develop a separate proxy bus to represent the Midwest ISO (a Balancing Authority that does not border the NYISO), then new rules will likely have to be added to address how this proxy bus will operate and how prices will be determined.

If the ISOs and RTOs determine that it would be appropriate to remove the eight path circuitous scheduling prohibition, changes to Attachment B to the NYISO's Services Tariff and Attachment J to the NYISO's OATT will be necessary to remove the prohibition.

D. Buy-Through of Congestion

Implementation of the Buy-Through of Congestion Broader Regional Market solution will require significant new Tariff revisions to implement. Necessary revisions will likely include:

- Revisions to the Joint Operating Agreements between the four ISOs/RTOs.
- New settlement rules for calculating off-contract path congestion costs/credits and passing them to the market where a particular transaction is being settled for payment/recovery.
- New settlement rules to permit the ISOs and RTOs to charge for, or pay credits to, market participants that scheduled transactions that affected congestion in, but that were not scheduled through, one of the four ISO/RTO Balancing Authorities.
- New bid parameters to permit entities scheduling external transactions to specify their willingness to pay for off-contract path congestion.

• Discounts offered.

- Rules to permit ISOs and RTOs to take willingness to pay congestion in neighboring markets into account when choosing which external transactions to schedule.

- New hedging products to help market participants manage exposure to off-contract path congestion costs. These could include the ability to schedule virtual transactions at external proxy buses and other virtual products that are designed to help manage congestion exposure within a specific ISO/RTO Balancing Authority. Complimentary additions to the market monitoring/market mitigation rules will likely be necessary to permit adequate policing of the expansion of virtual trading authority.

- Enhanced credit rules that account for the cost exposure presented by a possible obligation to pay congestion costs caused by an external transaction in a neighboring off-contract path market.

E. Congestion Management/Market-to-Market Coordination

Implementation of Market-to-Market Coordination with PJM Interconnection, the Midwest ISO and ISO-NE will likely require the following changes:

- Revisions to the NYISO's Joint Operating Agreements with PJM Interconnection and ISO-NE.

- Creation of a NYISO Joint Operating Agreement with the Midwest ISO.

- New settlement provisions to authorize the NYISO to pay an interconnected Balancing Authority for relief provided, and to allocate payments that the NYISO receives from participating Balancing Authorities.

- Development of rules for determining "entitlements" to use the capacity of a neighboring transmission system.

F. Enhanced Interregional Transaction Coordination

Implementing Enhanced Interregional Transaction Coordination will require the NYISO to make changes to its Services Tariff and/or Attachment B to its Services Tariff and Attachment J to its OATT to explain how Real-Time Commitment and Real-Time Dispatch will schedule import and export transactions, and to explain the pricing rules that will apply to external transactions that are scheduled in fifteen minute or five-minute increments.

G. Mitigation Measures

Once the design details of each of the Broader Regional Market solutions, including any associated hedging measures, have been determined, the NYISO and the other ISOs and RTOs will need to review their market monitoring and market mitigation measures to make sure the market monitoring and market mitigation rules adequately address the new capabilities that will be made available to market participants.

V. Stakeholder Participation

A. Technical Conferences

More than 100 stakeholder representatives participated (in person, or by phone) in the technical conference on Broader Regional Market solutions to Lake Erie loop flow that was held in Albany, New York on October 29, 2009. More than 90 stakeholder representatives participated (in person, or by phone) in the technical conference on Broader Regional Market solutions to Lake Erie loop flow that was held in Carmel, Indiana on December 15, 2009. The primary purpose of the technical conference that was held in Albany was to "roll out" the first draft of a detailed white paper describing the proposed Broader Regional Market solutions to stakeholders and to obtain their input on the ISOs and RTOs proposal. The ISOs and RTOs solicited written feedback from stakeholders at the first technical conference. Eleven parties responded to this request and provided comments on various components of the recommended solutions. Copies of the written stakeholder comments are available on the Midwest ISO's web site at:

http://www.midwestiso.org/publish/Folder/4dfde8_124a04ca493_-7c8e0a48324a

The presentations at the December 15, 2009 technical conference in Carmel, Indiana focused on addressing concerns raised by stakeholders at the Albany technical conference and/or in the written comments to the ISOs and RTOs.

B. NYISO Committee Discussions

The NYISO has given more than a dozen presentations on various aspects of the proposed Broader Regional Market solutions to its stakeholders in 2009 and in early 2010. The purpose of these presentations has been to ensure that New York stakeholders are adequately apprised of the status of the ongoing discussions between the ISOs and RTOs, and to solicit their input on the proposed long-term solutions to Lake Erie loop flow.

C. Going Forward Process

The implementation schedule proposed by the ISOs and RTOs in Section VI of this Report is intended to allow sufficient time to work through the details of implementing the five proposed Broader Regional Market solutions to Lake Erie loop flow, and to address valid concerns identified by stakeholders. The anticipated stakeholder process will include the preparation of a cost/benefit analysis of each of the proposed solutions by the ISOs and RTOs for discussion with their stakeholders, provincial authorities and appropriate regulatory agencies.

VI. Proposed Implementation Schedule

This Report presents a collective set of solutions that all of the ISOs and RTOs support. The following schedule is proposed for implementing the Broader Regional Market solutions. It assumes the timely availability of a Parallel Flow Visualization Tool; preferably, the tool that is being designed by the NERC IDC and OATI but, in the alternative, a tool designed and implemented by the ISOs and RTOs. The proposed schedule is intended to provide sufficient time for the ISOs and RTOs to address the numerous details that still need to be addressed before the proposed solutions can be implemented, including confirming the cost-effectiveness of each proposed solution and obtaining the necessary stakeholder and provincial or regulatory approvals. The proposed schedule is also intended to provide sufficient time and opportunity for stakeholder input prior to the implementation of each of the proposed solutions. It is the expectation of the ISOs and RTOs that all of the measures proposed below will be pursued in concert. The below schedule is a slightly modified version of the schedule that was presented to stakeholders at the December 15, 2009 technical conference. *See* Attachment B to this Report, slide number 70.

Potential/Proposed* Implementation Timeline

• Interface Pricing Revisions	
– NYISO Revisions - Design	2Q – 2010
• Regional PAR Coordination Operating Guide	
– Initiate Regional Study	2Q – 2010
• Parallel Flow Visualization	
– Software Ready	2Q – 2010
– Parallel Operations	4Q – 2010
• Buy-Through of Congestion	
– Design Development	4Q – 2010
– Implementation	3Q – 2011
• Congestion Management/Market-to-Market Coordination	
– PJM-NYISO-MISO Implementation	3Q – 2011
– Extend to Additional Regions	2012
• Interregional Transaction Coordination	
– Energy Scheduling between NYISO and PJM	4Q – 2011
– Extend to Additional Regions	2012

*Prospective timeline pending design development and approval from Market Participants, neighboring Balancing Authorities and the Commission.

VII. Implementation of Broader Regional Market Solutions by NYISO and ISO-New England

In addition to the Broader Regional Market solutions to Lake Erie loop flow that will be implemented by PJM Interconnection, the Midwest ISO, IESO and the NYISO, ISO-NE and the NYISO have agreed to work together to implement the Market-to-Market Coordination and Enhanced Interregional Transaction Coordination Broader Regional Market solutions. Due to the nature of the interconnection between New York and the New England region, the development of the Buy-Through of Congestion market solution does not appear to be necessary at this time. The NYISO and ISO-NE Boards of Directors have been significant participants in the effort to better coordinate the two neighboring markets.

The implementation of the proposed measures between the NYISO and ISO-NE is expected to better synergize these two Balancing Authorities' market rules. The Broader Regional Market improvements that the NYISO and ISO-NE have agreed to work to implement are described in greater detail in Attachment D to this Report.

VIII. Implementation of Broader Regional Market Solutions by NYISO and Hydro Quebec TransEnergie

In addition to the Broader Regional Market solutions to Lake Erie loop flow that the NYISO will implement with PJM Interconnection, the Midwest ISO and IESO, and the Broader Regional Market solutions that ISO-NE and the NYISO will work to implement, Hydro Quebec TransEnergie and the NYISO have agreed to implement the Enhanced Interregional Transaction Coordination Broader Regional Market solution at the Chateauguay D/C interconnection between the two Balancing Authorities. As the first implementation of Enhanced Interregional Transaction Coordination for the NYISO, the implementation with Hydro Quebec TransEnergie will pave the way for future Enhanced Interregional Transaction Coordination implementations between the NYISO and its other neighbors. Due to the nature of the interconnection between NYISO and Hydro Quebec TransEnergie, the development of the Buy-Through of Congestion and/or Market-to-Market Coordination market solutions do not appear to be necessary at this time.

The NYISO anticipates implementing the Enhanced Interregional Transaction Coordination Broader Regional Market solution, as described in Section II.F of this Report, at the Chateauguay D/C intertie with the Hydro Quebec TransEnergie control area in early 2011.

IX. Communications

Communications and correspondence regarding this Report should be directed to:

Rana Mukerji, Vice President of Market Structures
Robert E. Fernandez, General Counsel
*Robert Pike, Director of Market Design
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*Persons designated for receipt of service.

X. Service

The NYISO will electronically send a copy of or link to this Report to every party included on the Secretary's official service list in Docket Nos. ER08-1281-000 and ER09-198-000, to the official representative of each of its Customers, to each participant on its stakeholder committees, to the New York Public Service Commission, and to the electric utility regulatory agencies of New Jersey and Pennsylvania. In addition, the complete filing will be posted on the NYISO's website at www.nyiso.com. The NYISO will also make a paper copy available to any interested party that requests one. To the extent necessary, the NYISO requests waiver of the requirements of the Commission's Regulations to permit it to provide service in this manner.

XI. Biennial Reporting

The NYISO proposes to submit biennial updates to this Report to the Commission addressing the ISOs and RTOs ongoing efforts to implement the Broader Regional Market Solutions to Lake Erie loop flow. The NYISO's proposed biennial updates will address the status of the implementation of the Ontario-Michigan PARs and other issues related to implementing physical controls to mitigate Lake Erie loop flow.

XII. Conclusion

The NYISO respectfully requests that the Commission accept this Report as satisfying the requirements set forth in the Commission's July 16 Order and Order Granting Clarification and accept the proposed biennial reporting requirement that is proposed in Section XI of this Report.

Respectfully submitted,

/s/ *Alex M. Schnell*

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Robert E. Fernandez, General Counsel
Robert Pike, Director of Market Design
Alex M. Schnell
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January 12, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Rensselaer, New York this 12th day of January, 2010.

/s/ Alex M. Schnell
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New York Independent System Operator, Inc.
10 Krey Boulevard
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518-356-8707

Attachment A

Broader Regional Markets, Long-Term Solutions to Lake Erie Loop Flow White Paper

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

Attachment B

Broader Regional Markets,
Long-Term Solutions to Lake Erie Loop Flow
Slide Presentation from the December 15, 2009
Technical Conference Held in Carmel, Indiana

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

Attachment C

Broader Regional Markets,
Long-Term Solutions to Lake Erie Loop Flow
Slide Presentation from the October 29, 2009
Technical Conference Held in Albany, New York

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

Attachment D

Overview of Proposed Inter-Area Coordination Between ISO New England and New York ISO

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

Attachment E

Letter from ITC Holdings to NYISO
Dated December 23, 2009

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

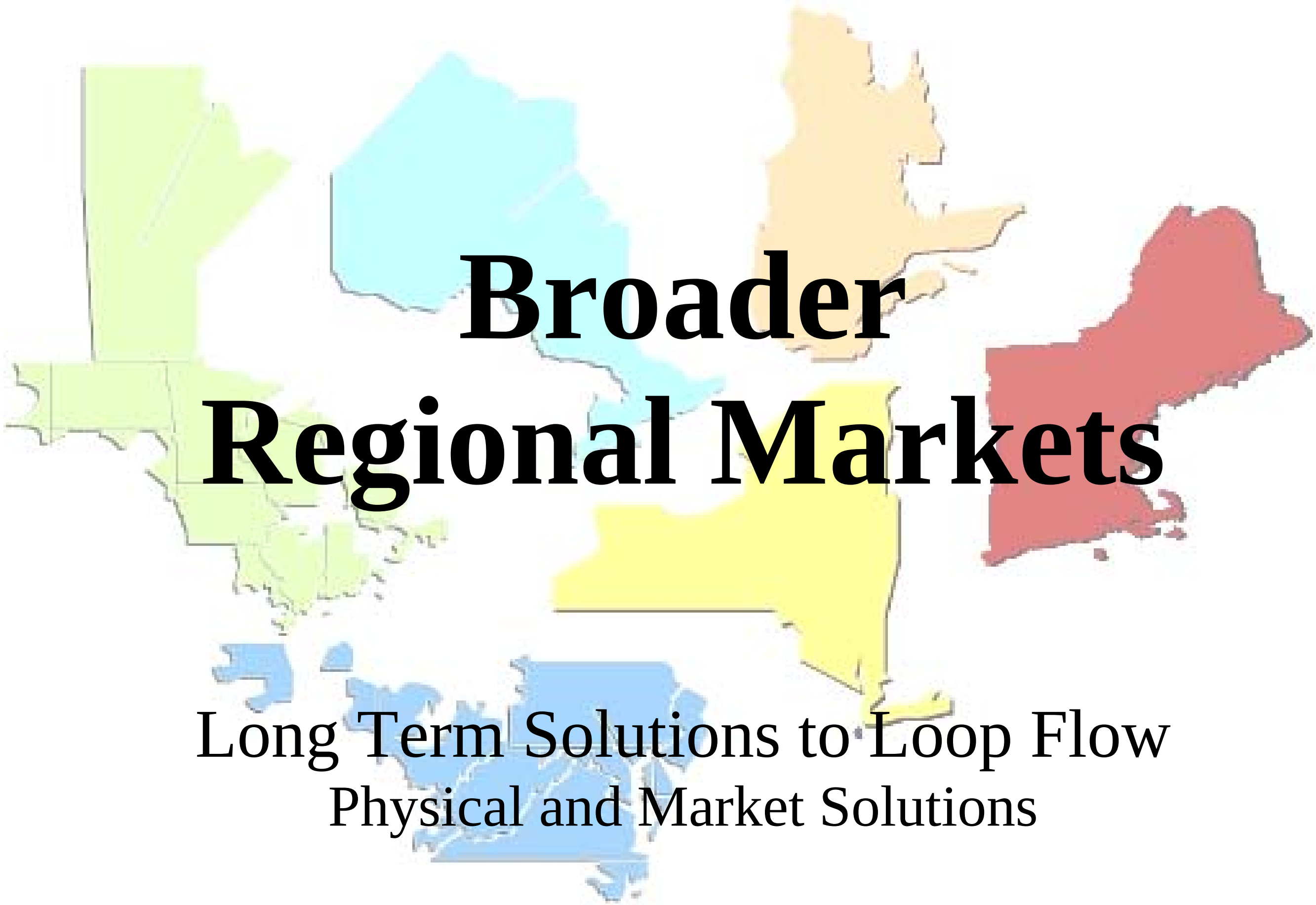
Attachment F

Northeast ISO Seams Resolution Report for the Third Quarter of 2009, Issued October 19, 2009

[Due to the size of the files associated with some of the Attachments, each Attachment is being individually submitted to the Commission.]

Attachment A

Broader Regional Markets, Long-Term Solutions to Lake Erie Loop Flow White Paper



Broader Regional Markets

Long Term Solutions to Loop Flow

Physical and Market Solutions

All information contained in this draft paper is a work-in-progress and is distributed for discussion and information purposes only. Responses and feedback are requested on the concepts captured within this document. The document shall be revised as the development and review of the proposals progresses.

TABLE OF CONTENTS

1. Summary

The desire of participants in ISO and RTO energy markets and in non-market areas is for a buyer and a seller to agree on a price and a quantity of electricity commodity and to deliver that quantity over the network from the place where it is produced to the place where it will be resold or consumed. The electric industry for years has grappled with the problem that electric power does not flow as requested on the grid, but rather, as described in Ohm's law, flows along the path of least resistance. The configuration of any and every element of the electric grid determines this resistance or impedance that governs the flow of electricity.

The disconnect between the "contract path" between source and sink becomes a reliability concern when the attempt to dispatch scheduled flows negatively impacts the system by creating actual flow patterns that are significantly different from scheduled flows due to the physical reality of the transmission system. The unscheduled flow patterns can load transmission facilities beyond their rated capacity even though these facilities could accommodate the nominal quantity scheduled for transfer had the actual flows matched those scheduled.

Unscheduled energy, also known as "loop" flow and "circulation" flow, results from the difference between the energy that is scheduled to flow across an interface connecting two balancing areas versus the amount of energy that actually flows across the interface between those two balancing areas. In addition, loop flows are caused by a balancing area's generation to load dispatch when a portion of the resulting flows travel over neighboring systems.

On July 21, 2008, to address the escalating impact of loop flows on its transmission system the NYISO filed tariff provisions at FERC that preclude the scheduling of transactions via circuitous paths around Lake Erie. A goal of these provisions was to increase consistency between the scheduling path and actual path of real power flows, thereby better aligning cost causation and cost allocation. The prohibitions were necessary, as there were no other adequate physical or market mechanisms readily available to control, or direct, physical real power flows around Lake Erie, or to permit recovery of costs when scheduled and actual power flows were not aligned. The Broader Regional Markets initiatives capture the desire to develop a more complete response to loop flows and the address the inconsistencies between contract path scheduling and actual flow of power. Lake Erie loop flows may remain as a practical reality of interconnected system operation. The accurate recognition and accounting of the costs incurred throughout the region in managing those flows must still be addressed.

The NYISO and its neighbors (IESO, MISO, PJM, ISO-NE and HQ) are working together to remove barriers to a broader regional market that spans balancing area boundaries and to improve the efficiency of electricity exchange in our region. This paper outlines market and physical solutions which have significant merits and that are expected to collectively result in vastly improved efficiency of the energy markets and transmission utilization on a regional basis. Improved regional efficiency will be achieved through coordinated operation of resources across markets to manage transmission congestion and improve transaction scheduling outcomes given market-to-market prices.

NYISO is working with its neighboring ISO/RTOs on specific market solutions including the: (1) Buy-Through of Congestion, (2) Congestion Management, and (3) Interregional Transaction Coordination solutions that are described below. Additionally, IESO and MISO are pursuing the implementation of Phase Angle Regulator (PAR) devices on the free flowing ties between Ontario and Michigan to improve control of flows on the facilities to align with schedules.

It is the recommendation of the ISO/RTOs that the preferred outcome is achieved through the collective implementation of all of these initiatives. Individually, they each only address a component of Lake-Erie loop flows and the efficiencies of a broader regional market. Buy-Through of Congestion responds to off-contract path transaction scheduling congestion management cost recovery, but does not address generation impacts on the network. Congestion Management enables more efficient use of limited transmission resources by providing compensation to generation resources to resolve system constraints. Finally, Interregional Transaction Coordination allows for more frequent region-to-region interchange to address similar resource limitations. The combined capabilities of the proposed solutions offer the potential to reduce uplift costs associated with real-time event management and congestion management; to improve the capability to incorporate intermittent resources, and to lower total system operating costs. The goal is to design the improvements in such a manner that they can be incorporated into the various ISOs and RTOs respective market designs without the need for fundamental changes to the rules that underlie the various interconnected markets.

2. Objectives

The set of solutions proposed in the document were developed to achieve a set of objectives that will lead to improved operational and market outcomes. Those objectives, as well as how the solutions collectively achieve those objectives is as follows:

- Reduce need for, frequency of, and magnitude of Transmission Loading Relief (TLR) events to address loop flow.
  - While TLR events are effective at addressing reliability constraints, they can result in significant levels of transmission service curtailment, disrupting the system operations and markets of the regions subject to the curtailments as they attempt to replace the removed energy and potentially significantly distorting the markets from their expected condition. Buy-Through of Congestion provides an economic selection based solution by creating the economic indicators necessary to avoid these scenarios either by discouraging the scheduling of power to these levels due to the high costs of managing these constraints, or by ensuring that the constraint management cost recovery mechanisms are available.

- Align constraint management cost recovery with sources of flow on the congested flowgate.
  - Addressing system reliability overloads requires the dispatch of otherwise off-cost generation to alleviate the flow constraints and a resulting increase in costs to that region. Parallel Flow Visualization and Buy-Through of Congestion facilitate the identification of the sources of loop flow and the allocation of the congestion management costs incurred to support these flows to those that are responsible for creating them.

- Reduce constraint management costs for consumers across region.
  - Congestion Management achieves a more cost effective resolution of system constraints by expanding the pool of assets that are capable of addressing the constraint. The availability of more cost effective solution options results in lower costs of constraint management.

- Improve regional price consistency and transmission utilization.
  - Congestion Management provides for more consistent prices across the borders as the collective assets are utilized to resolve system limitations.
  - Interregional Transaction Coordination provides the additional flexibility to adjust interchange schedules more frequently in response to changing market conditions, including the impacts resulting from increased intermittent power resources. More frequent adjustment of schedules

results in more consistent flow of energy in response to differences in prices between regions and lowers risk in scheduling decisions.

3. Physical Solutions

In the absence of a single ISO/RTO dispatching resources across the broad region surrounding Lake Erie, better conformance of actual power flows to scheduled power flows across the key interconnections is a desirable component of any plan to address the Lake Erie loop flow issue. Better matching of flows to schedule can be achieved through the use of "physical," i.e. transmission system equipment, solutions.

One solution is the use of a phase shifting transformer, also referred to as a Phase Angle Regulator ("PAR".) Such "controls" are in the process of being installed on the interconnection between Ontario and Michigan in order to mitigate inadvertent loop flows that can result in one party benefiting from services provided by another.

Implementing an effective regional physical solution to control or mitigate Lake Erie circulation should be a key component of any comprehensive solution that the NYISO and its neighbouring ISOs and RTOs develop. Using the Ontario-Michigan PARs to more closely match actual power flows to scheduled power flows will reduce unscheduled Lake Erie loop flows and their corresponding impact on congestion management costs and LBMP prices.

a. Ontario – Michigan Phase Angle Regulators

It is recognized that better conformance of actual power flows to scheduled power flows across the New York - Ontario and Michigan - Ontario interconnections is a desirable component of any plan to address the Lake Erie loop flow issue. In its August 21, 2008 Order in docket ER08-1281-000, the FERC reinforced this by encouraging the parties responsible for operating the Ontario-Michigan PARs to place them in service as soon as practical.

i. Installation

During 1999, the completion of international negotiations enabled work to commence on the installation of phase-shifting transformers (Phase Angle Regulators or PARs) and an autotransformer at the interconnection between Michigan and Ontario. This equipment was designed to both increase the import/export capacity of the interconnection and also to provide a means to manage loop flows through Ontario often referred to as Lake Erie Circulation (LEC). Implementation of this physical solution will go a long way toward reducing unscheduled, circulating power flows around Lake Erie. Ongoing operation of these facilities has been delayed due to a number of equipment failures, events and difficulties in getting operating agreements in place between the parties.

The failed equipment has been replaced and further protection upgrades to allow operation of the equipment are being completed. The latter is scheduled for completion by the end of the first quarter 2010, with (full) operation of the phase angle regulators anticipated to commence shortly thereafter.

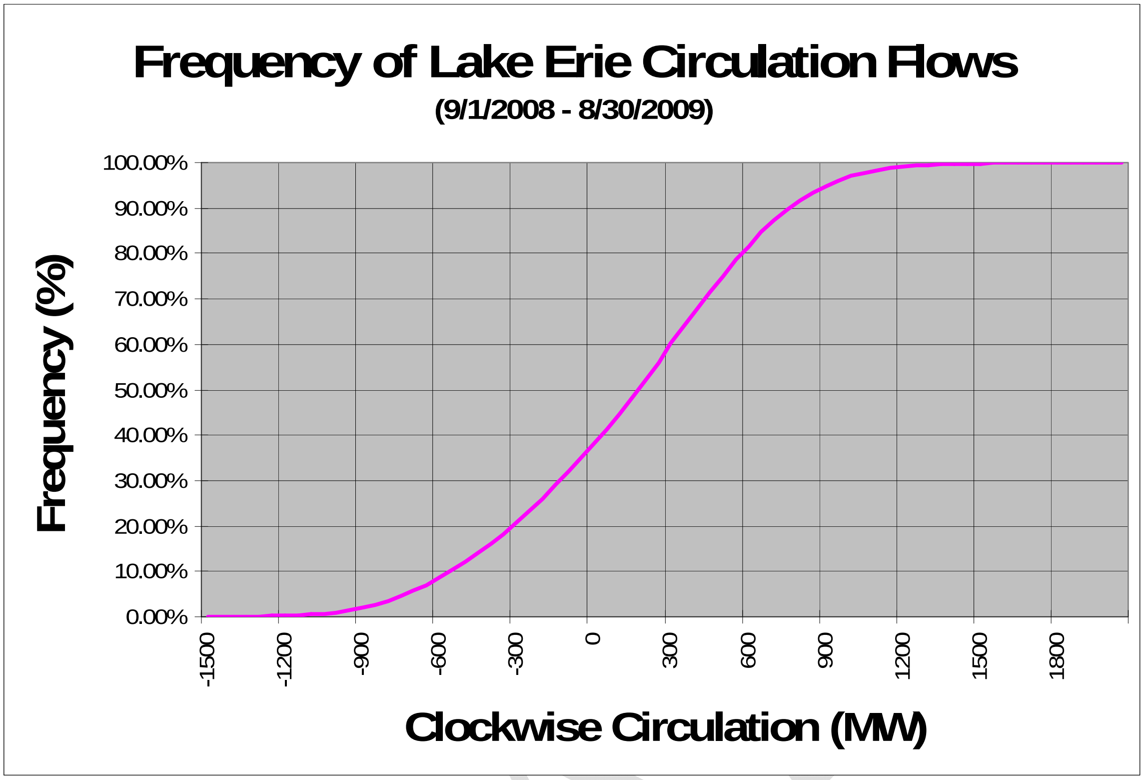
ii. Operating protocol

The operating protocols for the Michigan-Ontario PARs have been developed between ITC, MISO, and the IESO and are awaiting signature. They are to incorporate controlling actual flow to match scheduled interchange as provided under existing Presidential Permit PP-230-3.

Under normal system conditions, the phase-shifting transformers on the interconnection between Michigan and Ontario are to be operated such that the electrical flow on the Michigan-Ontario interface will, as far as practical, match the scheduled transactions across the Michigan-Ontario interface. Under emergency conditions, the phase-shifting transformers shall be operated in a manner that will help alleviate such emergencies consistent with good utility practices.

iii. Expected capabilities

The utilization of the Michigan-Ontario PARs will help to control a loop flow or a parallel path flow called Lake Erie Circulation (LEC). These PARs, with an effective phase angle control range of ±47 degrees under full load, are expected to be capable of controlling Lake Erie Circulation by up to approximately 600 MW in either direction. Control of Lake Erie Circulation to such levels should better enable scheduled power flows to be maintained between Ontario, Michigan and New York. The improved control over power flows should also greatly reduce the incidence of constrained operation on other southern Ontario interfaces affected by loop flow. A sample of historical flow distribution for LEC is shown in the figure below.



Note: Clockwise circulation is evidenced by Michigan to Ontario to New York flows in excess of schedule.

b. <u>Coordination Operation of Power Control Devices</u>

The operation of the Phase Angle Regulators (PARs) by the four markets around Lake Erie can influence the amount of circulation flows. PARs are electro-mechanical devices that change the impedance on the system. They neither create flows nor absorb flows (except for insignificant losses). PARs can be used to alter the flows to follow a different electrical path or to better follow the contract path, as in the planned Ontario-Michigan PARs. There are a number of operating limitations that prevent the use of PARs to eliminate circulation flows altogether. Since Coordinated operation of the PARs in the four markets around Lake Erie can enhance the degree to which circulation flows are managed, it is important that the operation of PARs by the four markets around Lake Erie be coordinated and included in the long term solutions to loop flows. In addition to PARs, variable frequency transformers, series capacitors, and other such devices have the ability to alter flows that should be coordinated and included in solutions to loop flows.

The PARs that operate around Lake Erie include the PJM and NYISO interface ties at Waldwick (JK), Linden and Hudson (ABC) and Ramapo, the NYISO and IESO interface ties at St. Lawrence and the IESO-MP and IESO-MH interface ties. Of the four ties between MECS and IESO, one is controlled by a PAR (J5D) and the other three do not currently operate with a PAR (the two PARs at Lambton are in bypass and replacement B3N PARs have been installed).

Except for the PARs on the IESO-MP interface and the IESO-MH interface, most PARs are not currently operated to continuously control flows such that schedule flow equals actual flow across an interface. However, most PARs were installed to address a very specific condition and are usually successful managing that one specific condition. As conditions change such that managing that one specific condition is no longer needed, it is very difficult to have the PARs operate in a manner that is different than their design. A loop flow study report issued by Midwest ISO and PJM in May 2007 (http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf) found a strong correlation between the operation of the PARs around Lake Erie and circulation flows. Under ideal conditions, the PARs would be operated such that they always minimize circulation flows. As stated previously, there are operating limitations on how much power can be controlled by a PAR, there are restrictions on the number of tap movements allowed per day and there are dead bands used to delay the response of the PAR. All of these real-world issues prevent operating the PARs under ideal conditions. Since the PARs are not going to always be able to minimize circulating flows and are not able to operate continuously under ideal conditions, it is important that the contributions to circulation flows be identified in the IDC. Under this scenario, the PARs are allowed to operate in accordance with their design requirements and contractual obligations. However, the impact of PAR operation to the contributions to Lake Erie loop flow needs to be identified so that everyone joins in managing these flows during periods when congestion exists.

Two key recommendations in the 2007 study are:

- IESO and NYISO report their market flows to the IDC (or the necessary data for the IDC to calculate the market flow) and participate with Midwest ISO and PJM to manage circulation flows around Lake Erie when congestion occurs.
- The four parties around Lake Erie develop a comprehensive plan on the operation of the Michigan-Ontario and NYISO/PJM PARs to control loop flows around Lake Erie.

In support of the May 2007 MISO, PJM study recommendations and to continue the advancement of regional PAR coordination efforts the following activities will be completed:

- A regional study will be initiated during 2010 to identify reliability and market impacts of the PARS or other controllable devices having a regional impact on Lake Erie loop flows. This study will also identify significant regional paths or flowgates impacted by Lake Erie loop flows.

- Upon completion of the analysis and necessary updates to the existing FERC approved PAR Operating Protocols, regional operating guide recommendations will be developed and implemented by the four parties to better manage Lake Erie loop flow through the coordinated operation of the identified significant controllable devices. This includes implementing the necessary communications infrastructure and regional business processes to facilitate regional coordination of the identified controllable devices.

c. NYISO Circuitous Path Prohibitions

The NYISO tariffs currently contain provision which preclude the scheduling of transactions via eight circuitous paths around Lake Erie. Inconsistencies between external proxy pricing methodologies between PJM and NYISO led traders to schedule transactions on a contract path that was significantly different than the actual power flow conditions. Subsequent investigations determined that regardless of the pricing provisions, traders had the opportunities to disguise the ultimate source or sink of their transactions to achieve desired settlement outcomes. The NYISO's circuitous scheduling path prohibition was necessary as there were no other mechanisms readily available to the NYISO either to control, or direct, physical real power flows around Lake Erie, or to recover costs when actual and scheduled power flows were not aligned.

The NYISO believes that the existing NYISO prohibition on scheduling via the circuitous paths around Lake Erie is compatible with, and comparable to the outcomes achieved with tag-based pricing. The NYISO acknowledges that traders follow market signals and may be unaware of the resulting actual power flow on the network. The NYISO is currently unaware of any benefit, market or reliability based, to be achieved by allowing transactions to be bid on a path inconsistent with the predominant flow of power.

The purpose of the solutions defined in the remainder of this paper is to provide mechanisms to either control actual power flow to better match scheduled power flows or to more accurately price, assign and recover congestion costs at times when actual power flows diverge from scheduled power flows. The possible removal of the current prohibition on scheduling transactions via circuitous paths around Lake Erie will be considered after validating the completeness of the solutions proposed herein following their implementation.

d. ATC/AFC Coordination

Current TTC/ATC/AFC calculations and coordination between the New York Independent System Operator (NYISO) and PJM Interconnection (PJM) is performed as specified in Article Thirteen of the NYISO/PJM Joint Operating Agreement. This agreement specifies that both parties will exchange scheduled outage information on all interconnection and other transmission facilities that have the potential to impact TTC/ATC/AFC values and will also exchange the projected status of scheduled outages of those same transmission facilities for a minimum of eighteen (18) months or more if available. The Parties also exchange interchange schedule information to permit the calculation of TTC and ATC/AFC values. This agreement also calls for each Party to provide the other with transmission configuration changes and generation additions and retirements.

Transmission system impacts are also coordinated as needed and with other Reliability Coordinators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual Security Operation Limit (SOL), Interconnection Reliability Operation Limit (IROL), Control Performance Standard (CPS), or Disturbance Control Standard (DSC) violations. In instances where there is a difference in derived limits, both parties respect the most limiting parameter. A Party who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) that impacts the other Party issues an alert to the other Party without unreasonable delay. Both Parties confirm reliability assessment results and determine the effects of operational issues within its own and the other Party's areas. The Parties discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection and in line with NERC reliability standards at all times.

Current TTC/ATC/AFC calculations and coordination between the Midwest ISO and PJM are conducted in a similar fashion as described above, and are performed in addition to calculations in support of the Congestion Management Process in place between the Midwest ISO and PJM. The Congestion Management Process requires the establishment of Firm Flow Limits on Coordinated Flowgates. This calculation determines the directional market flow impacts on all Coordinated Flowgates and is used to determine the portion of those flows in each direction that should be considered Firm and Non-firm for both the current and next hour. Additionally, as frequently as once per hour, but no less frequently than once every three months, each Party submits to the Reliability Coordinator sets of data describing the marginal units and their associated participation factors for generation within the market footprint. This data is used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

This additional Congestion Management Process effectively extends the value of the TTC/ATC/AFC calculation processes by including generation impacts on constrained flowgates which can be dispatched to maximize the use of constrained transmission facilities and minimize the need to use TLRs to control transmission congestion created by loop flows.

Each of the ISOs have established market mechanisms for reviewing and approving firm flow transaction requests. All of the offerings accomplish the tasks of observing the physical capabilities of the system, valuing that service and offering the hedging opportunities of the potential observed costs of transmission congestion within that ISO. While incremental improvement opportunities may exist to the allocation process, the opportunities are not seen as a solution to loop flows or to system congestion. Loop flow exists due to the interconnected nature of the power systems and the need to maximize the value of that system to move lower cost power to the consumers.

4. Market Solutions

a. Parallel Flow Visualization

Network flows on an interconnected grid are the composite result of all the individual actions taken in the interconnected regions to dispatch generation to meet their load, to direct flow on controllable facilities, and to transfer energy between regions. No single region currently has access to sufficient information to decompose line and flowgate flows into the unique sources of those flows.

The goal of a market flow calculator is to facilitate the calculation of impacts, to assemble the necessary real-time data, to perform the generation-to-load calculations and to make available common and consistent information regarding the sources of power flows and their impacts available to all regions. The market flow calculator will distinguish the source of flow between (A) each separate region's impacts associated with generation-to-load dispatch and (B) individual transaction impacts.

Pseudo ties, used for extending regions boundaries, will be included in generation-to-load calculations. Pseudo ties are not tagged and are modeled in the IDC consistent with dispatches of internal resources. Dynamic schedules are identified for curtailment purposes via NERC tags and would be visible to the IDC process as an interchange schedule. These impacts would be included in transaction impacts, not generation-to-load impacts.

The NERC IDC Working Group is currently tasked with defining the necessary data reporting requirements and developing with OATI the specification for performing a market flow calculation. Data reporting by the Balancing Authorities will become required to support the accurate computation of market flows.

The future market flow calculation process will require significantly more data at a greater frequency. The magnitude of the expected benefits will be tied to the quality of the data reporting. The collective ISOs support the accurate, complete and timely reporting of the necessary information to achieve the region wide implementation of the parallel flow visualization process and the visibility it provides to market flow impacts. The availability of this information is required to support the implementations of Congestion Management and Buy-Through of Congestion and the management of Lake Erie loop flows. In the absence of a NERC supported solution, alternative solutions will need to be developed to achieve this information reporting. To support the collective ISOs commitment to a timely implementation of the market solutions, the ISOs will evaluate by June 1st 2010 the state of the Parallel Flow Visualization implementation. If the solution is determined to be abandoned, unsupportable, or unachievable, the ISOs will pursue alternative solutions to the visibility initiative in an effort to maintain the proposed solutions implementation timelines.

i. Interchange Distribution Calculator (IDC) Data Reporting

Identifying the transactions associated with unscheduled flows within the IDC is a key element to the solutions identified within this white paper. Reliability Coordinators monitor real-time flows using RTCA and SCADA. This process is effective monitoring total flow but does not identify the source and magnitude of parallel flows.

A comprehensive parallel flow visualization motion was approved at the May 6, 2009 NERC Operating Reliability Subcommittee (ORS) meeting. Highlights of proposal included:

- RCs would report their generation-to-load impacts to the IDC on a real-time basis or make arrangements to have someone report on their behalf.
- The IDC would indicate the source or all flows on a flowgate and the priority of these flows (tag impacts, generation-to-load impacts and market flow impacts).
- An RC experiencing congestion would have visualization of the magnitude and source of all flows affecting their flowgate using information from the IDC.
- An RC experiencing congestion would request an amount of flow reduction that would be processed by the IDC. A relief obligation would be issued to all parties contributing to the loading.
- NAESB will establish a methodology for assigning generation-to-load flows into the appropriate priority bucket.

Subsequently the NERC ORS, at their November 2009 meeting, approved a motion to move forward with the parallel flow visualization project. This motion included the vendor selection and a detailed timeline for the implementation. The solution will include a single common source of the market flow calculation, using an open vetted methodology, which would offer transparency and consistency in the results and a single, common repository of the results to make available identical information to all involved parties. The solution will include a historical archive of results and auditability of those results. The timeline identifies November 1, 2010 as the date when data gathering and the trial period for the parallel flow visualization project will begin. The trial period is expected to last twelve to eighteen months.

b. <u>Buy-Through of Congestion</u>

The current practice for scheduling of interregional transactions only requires scheduling parties to pay for the congestion charges assessed by the Balancing Authorities that are part of the “contract path” over which an external transaction is scheduled. Costs that an external transaction imposes on Balancing Authorities that are not included in the contract path are not currently considered in the scheduling process, nor are they charged to the scheduling entity. Buy-Through of Congestion addresses this shortcoming by more completely assessing the congestion charges associated with scheduling an interregional transaction to the scheduling entity.

The movement of power from Balancing Authority to Balancing Authority is typically scheduled on a contract path methodology. In reality, power moves consistent with the laws of physics and the relative impedances of the various elements of the transmission system, and actual power flows can be quite different from the path over which a particular transaction is scheduled to flow.

Managing power that flows in a manner that is not consistent with the path over which transmission service is purchased and the transaction is scheduled (contract path) can be a costly endeavor when the associated uncontrolled off-contract path loop flow causes congestion on prime transmission corridors. Removing these power flows by implementing the NERC Transmission Loading Relief (TLR) procedures can address the impacts, but employing TLR creates market and operational inefficiencies through the loss of expected energy deliveries without regard to economic rationing principles. In addition, the existing TLR process does not take into account the scheduling party's possible economic willingness to pay to maintain its transaction schedules or the economic viability of moving power between regions.

More efficient utilization of the transmission network and more accurate transaction scheduling decisions can be achieved if the cost of managing the off-contract path congestion can be calculated and appropriately allocated to the scheduled power transfers that caused the congestion, providing both contract path and off-contract path flows equivalent cost exposure for equivalent use of the transmission network.

Transactions scheduled using firm transmission service are responsible for their congestion impact along the contract path. The scheduling of transmission service is separate and distinct from the responsibility for paying congestion charges, and is not equivalent to ensuring a congestion cost-free path of transmission access. Transacting parties, regardless of service provisions, must still supply bids and offer and be evaluated and selected in economic merit order.

In some markets the cost of firm service may include a hedging product to protect against potential congestion charges. Hedges against congestion costs can also/alternatively be acquired through the available supplemental Financial Transmission Right or Transmission Congestion Contract auctions. The cost of the available hedging products representing a proxy for the potential congestion cost exposures. Hedging mechanisms are limited in their scope to the market from which they are procured. To the extent that service is necessary across multiple regions, multiple products may need to be acquired.

While the costs of parallel flow impacts have not been historically allocated to external transaction schedules, that outcome was not based upon the expectation that the costs incurred by off-contract path Balancing Authorities were not the responsibility of the scheduling party. Rather, the problem was that it was not technically feasible to accurately assign parallel flow impacts to a particular transaction. Congestion costs could not be applied to off-contract path impacts until the evolution of the individual marketplaces achieved the ability to identify and quantify the costs of these impacts and the collective marketplaces achieved a solution that would allow for the application of these charges to the sources. The Parallel Flow Visualization Tool and Buy-Through of Congestion solution will enable the ISOs and RTOs to accurately identify, assign and apply congestion charges to off-contract path flows, thereby comparably charging external transactions for their contract path and off-contract path congestion impacts. All transmission customers will have the opportunity to indicate their willingness (or unwillingness) to be responsible for these congestion charges. Removing a transaction schedule because the scheduling entity has taken an economic position that is no longer viable is a scheduling decision made by the participant. It is not a violation of the firm transmission service arrangement if the customer decides that it is unwilling to pay for redispatch service in off-contract path markets where its transaction has a congestion impact.

The objective of Buy-Through of Congestion is to provide an economics based alternative to administrative curtailment through TLR actions. The main steps in the process are to (a) identify the sources of loop flow caused by Balancing Authority to Balancing Authority schedules via the NERC Interchange Distribution Calculator (IDC) tools, (b) determine the costs incurred in supporting the loop flows via each impacted region as indicated by their locational marginal prices or equivalent, and (c) allocate those costs to the scheduling entity or remove the associated schedules if the scheduling entity is not willing to pay the full cost of completing its transaction(s). The Buy-Through of Congestion processes will result in a more complete identification of and accurate assignment of the costs to move power between regions and provide an economics based alternative to the administrative TLR curtailment processes.

The ability (or point in time) of the subject Balancing Authorities to engage/participate in the Buy-Through of Congestion process will vary. Until such time as the entity is able to place into service the tools and procedures to participate, the entity will continue to utilize the TLR process to remediate the impact of off contract path loop flow induced congestion.

i. Responsible Control Area Duties

The sink Balancing Authority of the inter-control area transaction, or the last control area of the four Lake Erie ISOs to be engaged in the transaction, shall be responsible for administering the Buy-Through of Congestion provisions for that transaction. This entity is referred to in this paper as the “Responsible Control Area.” The Responsible Control Area’s duties include (a) obtaining as part of an entities transaction bid an indication of its willingness to pay (or not to pay) congestion charges caused by the off-contract path impact of that transaction, (b) scheduling or, following a request from the monitoring ISO, removing a transaction in recognition of the transaction’s loop flow impacts, the expected congestion charges associated with the loop flow and the scheduling entity’s indicated willingness to pay those congestion charges, and (c) processing the collection and distribution of settlement charges for the transaction.

Settlement of congestion charges through the Responsible Control Area is necessary as the market participant that is scheduling a transaction may not be a market participant of one or more of the off-contract path control areas that experience additional congestion as a result of the schedule. This process alleviates the need for entities scheduling inter-control area transactions to be participants in every market that could be impacted by the transactions they schedule, although they may still need to become members of the relevant market to participate in the opportunities to hedge these congestion costs..

ii. Monitoring ISO Duties

Each Balancing Authority will be responsible for utilizing the Parallel Flow Visualization tools, currently being developed by the NERC IDCWG, for determining if the congested flowgate is being impacted by parallel flows from transaction schedules. In this situation, the Balancing Authority is acting as the "Monitoring ISO" for the purposes of Buy-Through of Congestion. Subsequent to the identification of parallel flow impacts on the constrained flowgate, the Monitoring ISO will initiate with the respective Responsible Control Area(s) a "request to review" the schedules of these transactions. This request will identify the transactions to be reviewed. Subsequently, the Monitoring ISO will calculate the appropriate congestion charges associated with the remaining transaction schedules that needs to be recovered and will provide that information to the respective Responsible Control Area(s).

iii. Congestion Charge Bidding Indicators

Currently, traders assess the opportunities to transfer power between regions based upon projecting the prices in the regions, transaction costs incurred in arranging the power transfer, hedging opportunities and the risks associated with their predictions. The allocation of congestion costs for transaction impacts incurred by off-contract path regions to the traders who opt to buy-through of congestion will present an additional cost risk that these traders will have to take into account when scheduling transactions.

The ISOs and RTOs will offer enhanced bidding capabilities that will improve the management of this new risk. The bidding enhancement will allow the scheduling party to indicate if they are, or are not, willing to pay the congestion charges caused by their transactions off-contract path flow impacts. If a transacting party indicates it is not willing to pay congestion charges its transaction will be removed by the Responsible Control Area when the off-contract path flows created by the transaction adds to the congestion costs in a Monitoring ISO. Once removed, the transaction will not be reinstated until the neighboring ISO indicates that the congestion on the impacted flowgate has been relieved. Transactions that indicate they not willing to pay congestion charges will not incur such charges for the period of time necessary to remove the transactions after congestion is identified.

Several parties have expressed the need for the Buy-Through of Congestion concept to include the ability to specify a real-time "up-to" congestion charge limitation, indicating the maximum amount of off-contract path congestion the entity scheduling a transaction would be willing to pay. The ISO's acknowledge that the Buy-Through of Congestion concept will result in some of the cost risk exposure being returned from each regions internal load to the transacting parties whose schedules produce the off-contract path congestion. The ISOs are committed to providing the necessary data transparency and visibility of projected and occurring congestion costs to allow traders to consider their cost exposure (See section 4.b.v) when requesting a schedule or alternatively to self-remove their schedules upon observations of congestion charge allocations. The ISO's additionally acknowledge the need to develop the necessary congestion cost hedging products to allow traders to purchase the congestion management product at specified values within the respective Day-Ahead Markets, where applicable. Actual experience has not shown the need for an up-to congestion product to be necessary if there is adequate real-time price transparency around price differences. For these reasons, the ability to additionally specify a real-time "up-to" congestion component will not be available.

iv. Management of Congestion Cost Exposure

Buy-Through of Congestion introduces a new cost allocation mechanism to interchange schedules in the region that must be accounted for when evaluating the viability of a schedule. In addition to opting to not be willing to pay for congestion costs, several products already exist in the various regions markets to provide hedges or costs stops against those charges.

NYISO:	Up-to congestion cost available via wheel-through transaction product in DA. Opportunities to expand virtual trading to the proxy bus locations.
PJM:	Up-to congestion product available in DA. 20-minute advance notice schedule termination. Virtual bidding options available.
MISO:	Up-to congestion product available in DA. 20-minute advance notice schedule termination. Virtual bidding options available.
IESO:	No products currently available.[1]

Hedging Opportunities in the MISO Market:

The MISO Energy and Operating Reserve market supports several market products to hedge against unplanned events and volatility that can occur in the real time market.

In the long term planning horizon Auction Revenue Rights (ARRs) are allocated to market participants based on the firm historical usage of the MISO transmission system. The ARRs constitute a hedging mechanism against price uncertainty in the Financial Transmission Rights (FTR) auction. FTRs can be obtained on a monthly or annual basis.

[1] Current there is no day-ahead market nor LBMP within Ontaria

This provides a level of hedging against the congestion charges that a market participant may be exposed to in the Day Ahead market.

In the Day Ahead market, load serving entities and generators can submit fixed or price sensitive bids and offers. These cleared bids and offers provide price certainty against real time market events. In the Day Ahead market, participants may also submit virtual transactions at any CPNode or trading hub. These virtual bids and offers need not be related to a physical resource or load asset. In addition to the above hedging opportunities, a participant can also submit fixed, dispatchable and Up to Congestion schedules. These schedules are cleared and settled based on the Day Ahead market clearing process.

Hedging Opportunities in the NYISO Market:

For the NYISO, the Day Ahead Market currently provides one option for hedging the buy-through of congestion cost. This option is the wheel-through transaction product in the Day Ahead Market which provides the ability for a trader to explicitly hedge the congestion cost between two external proxy buses by providing an ‘up-to’ offer for the wheel-through transaction.

The NYISO is also considering two additional products for the Day Ahead Market which may provide more hedging flexibility. The two additional products would be (1) to allow Day Ahead virtual trading at the external proxy bus locations and (2) to allow Day Ahead virtual trading based on the price delta of two locations (or virtual spread bid). Virtual Day Ahead trading at the external proxy bus would allow for virtual generation or virtual load transactions at the external proxy buses to be scheduled economically in the Day Ahead Market. The virtual Day Ahead spread bidding option would allow for a virtual position to be taken in the Day Ahead Market based on the LBMP delta of the two locations. The virtual transaction trader would provide an ‘up-to’ offer indicating the willingness for the transaction to be scheduled based on the price difference between the source location and sink location of the offer.

v. Data Transparency

In order to be able to trade energy effectively, the trader must be able to understand the dynamics of both the revenues and expenses to a trade. Buy-Through of Congestion adds a new element of expense to energy trading by adding a new variable to the trade.

Each Monitoring ISO has the responsibility to provide adequate transparency to any and all buy-through of congestion charges that a trader may incur. To do this, each Monitoring ISO must make available the following information on a nominal five minute basis:

(1) The contract path impacts on all significant flowgates as calculated by the IDC;
(2) The shadow costs on all significant Monitoring ISO flowgates; and

(3) The actual Lake Erie Circulation (LEC) occurring.

The information above is required so that each and every market participant has an understanding of the current exposure to buy-through of congestion. Each Monitoring ISO will use good industry practices to display this information.

Through stakeholder processes, each Monitoring ISO will request market participant feedback to help provide as much transparency as possible to the Buy-Through of Congestion product.

Third Party Tools

In addition to the data provided by each Monitoring ISO, third party services also exist to aide in data visibility and data presentation. These third party tools:

(1) Allow a trader to study future transactions providing an illustration of the impacts (direct and parallel) any contract path trade may have on flowgates;
(2) Allow a trader to assess current contract path impacts (direct and parallel) that exist on flowgates; and
(3) Will allow, in the future, a trader to determine current contract exposure by incorporating current flowgate shadow costs with current impacts.

vi. Transaction Removal Process

The removal of transactions will be accomplished through a coordinated process between a Monitoring ISO and the Responsible Control Area(s). A Monitoring ISO maintains responsibility for ensuring their respective systems are operated to specified reliability standards. Upon detection of a flowgate being constrained in the next hour, a Monitoring ISO will determine if the flowgate is being impacted in a net forward direction by transaction schedules' loop flow impacts, as reported by the Interchange Distribution Calculation (IDC). The IDC will additionally identify each transactions individual impacts on the congested flowgate and the Responsible Control Area for each transaction. The same impact thresholds as are employed in the NERC TLR protocol will apply to the identification of transactions with loop flow impacts on a flowgate.

Loop flow impacts on a flowgate will be influenced by the status and ability of the in-service Phase Angle Regulators to conform actual power flows to scheduled flows. In the absence of PARs, the loop flow impacts are the shift factors of the transaction from source to sink on the flowgate. The loop flow impact across controlling PAR ties will be considered to be zero. For the scenario of a partially controlling PAR, the loop flow impacts will be determine by scaling the normally calculated shift factors by the amount of overflow occurring on the PAR.[2] This calculation will be performed within the IDC.

[2] http://www.nerc.com/docs/oc/idcwg/idcwg-change-orders/CO_nn_partial_phase_shifter.pdf

The Monitoring ISO will notify with the Responsible Control Area(s) to initiate a review of the set of transactions creating loop flow impact on the constrained flowgate. This communication could potentially be automated in the Interchange Distribution Calculator (IDC) whereby it populates a message on the NERC Reliability Coordinator Information System (RCIS) to all reliability coordinators. The Responsible Control Area(s) will review the transaction set and their respective bid indication of willingness to pay for congestion costs. For those that are not willing to pay congestion costs, the Responsible Control Area will remove the transaction schedules and communicate with the Monitoring ISO when those reductions have been completed. At the same time, the Responsible Control Area will update the status of the removed transactions in the IDC.

The NERC TLR procedures will remain as an active viable tool to the system operators to address system overloads. The purpose of the Buy-Through of Congestion solution is to enable recovery of costs associated with managing constraints. By more accurately reflecting the true price of scheduling a transaction, it is expected to reduce the need to utilize the TLR procedures. However, Buy-Through of Congestion is not a mechanism to respond to system overloads under the assumption that increased congestion will cause transaction schedules to be reduced. The TLR procedures will continue to serve this role. TLR procedures take priority and must not be impacted by the existence (or not) of buy-through of congestion provisions. TLR procedures may have to be utilized even if participants are willing to buy-through congestion if the Monitoring ISO is not capable of redispatching for the flowgate that is over its limit. To allow TLR actions to be called in a timely manner in such situations, the “Buy-Through of Congestion process should be initiated as early as possible in the hour ahead.

vii. Transaction Re-instatement Process

Once a market coordination process has been invoked on a flowgate due to congestion, no transaction schedules that would impact the flowgate will be permitted if the entity scheduling the transaction indicates it is not willing to pay congestion costs. Transactions that indicate they are willing to pay for congestion associated with their loop flow impacts will continue to be evaluated in the normal ISO scheduling practices.

A Monitoring ISO will continue to evaluate congestion / constraints on the source flowgate and will notify the Responsible Control Area(s) when the constraint is relieved and the ISO projects that it will be able to manage the flowgate even if the schedules are re-instated. The release of limitations on the flowgate will match the timing of the TLR reload procedures, with notification occurring by the bottom of the hour for next hour scheduling changes.

viii. Forecasted Congestion impact to Scheduling Processes

The Buy-Through of Congestion process is initiated on a comparable basis to the calling of a TLR level 3a. The transmission system is secure; one or more of the Monitoring

ISO's internal transmission flowgates are expected to be at their System Operating Limits (SOL) or Interconnection Reliability Operating Limits (IROL) in the next hour; and the IDC is indicating that there are transactions external to the Monitoring ISO that have a net impact on these flowgates that is at or above the TLR Curtailment Threshold on those facilities. Unlike the TLR process, however, there is no differentiation between transactions using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service.

Once the Buy-Through of Congestion process is initiated, only transactions that indicate they are willing to pay for congestion associated with their loop flow impacts on the identified flowgate(s) will continue to be evaluated in the normal ISO scheduling practices. Transactions that would impact the identified flowgate(s) where the entity scheduling the transaction has indicated it is **not** willing to pay congestion costs, will be rejected. Any consideration of such transaction in future hours will be in accordance with the "Transaction Re-instatement Process" above.

ix. Congestion Cost Determination

Congestion costs will be calculated based upon the LBMP prices, or equivalent, determined either in the region experiencing the flowgate congestion or thru the coordinated Congestion Management activities between regions impacted by the off-control path loop flows. Market participants should be provided a way to evaluate their congestion cost exposure in near-real-time.

With Buy-Through of Congestion, those transactions that wish to opt out of buying through any parallel congestion costs could be removed if congestion is forecasted on the parallel path. The forecasted congestion costs would only be used to determine the need for removing those transactions that did not wish to buy through. When determining congestion charges for those that opted for buying through, the congestion charges would be based on the actual real-time congestion costs that were observed, which may be zero.

Once a market participant indicates a willingness to buy-though the parallel flow congestion charges for a transaction, the market participant shall be subject to charges from the Monitoring ISO.

The non-contract path congestion charges will be calculated using:

(1) The actual real-time shadow cost of the flowgate(s), or comparable LMP differences along the non-contract path;
(2) The transaction's transfer distribution factor[3] on the flowgate; and
(3) The contract path transaction schedule.

The non-contract path congestion charges will be calculated with the information above using the Monitoring ISO's internal billing rules. As an example of one internal billing

[3] http://www.nerc.com/docs/oc/idcwg/training/IDC%20Factors.pdf

rule, some of the Monitoring ISOs calculate a bill using five minute information while other Monitoring ISOs calculate a bill using average hourly information.

All buy-through of congestion charges will be processed by the Monitoring ISOs experiencing congestion on flowgates that can be attributed to energy contracts. The charges will be passed from the Monitoring ISOs that calculate the congestion charges to the Responsible Control Area. The contract will receive notice of the congestion charges as part of the sink control area's invoice.

Example:

A market participant enters into a contract to buy 100 MW of energy from a source located within the Independent Electric System Operator (IESO) and sell the 100 MW of energy to a location within the New York Independent System Operator (NYISO). We will refer to the 100 MW contract as having a contract path from IESO to NYISO.

During the dispatch hour, the following conditions exist for only one five minute interval during an hour:

(1) The Midwest ISO has an actual constrained flowgate in real-time with a shadow cost of $70/MWh;
(2) The 100 MW contract from IESO to NYISO has a 15% transfer distribution factor on the Midwest ISO constrained flowgate; and
(3) The contract path transaction schedule is 100 MW.

For the scenario described above, the calculation becomes $70/MWh * 15% * 100MW * 5/60 h which equals $87.50. The $87.50 would be billed to the contract holder via a bill adjustment to the contract holder's NYISO invoice.

Similarly, if the MISO had calculated a LMP for both the NYISO and IESO, then a comparable calculation could be the transaction contract MWs multiplied by the difference between the MISO LMP for the NYISO minus the MISO LMP for the IESO. With the above calculation, the difference in LMPs would have already captured the contracts transfer distribution factors on the non-contract path.

Please refer to the diagram below which illustrates this example.

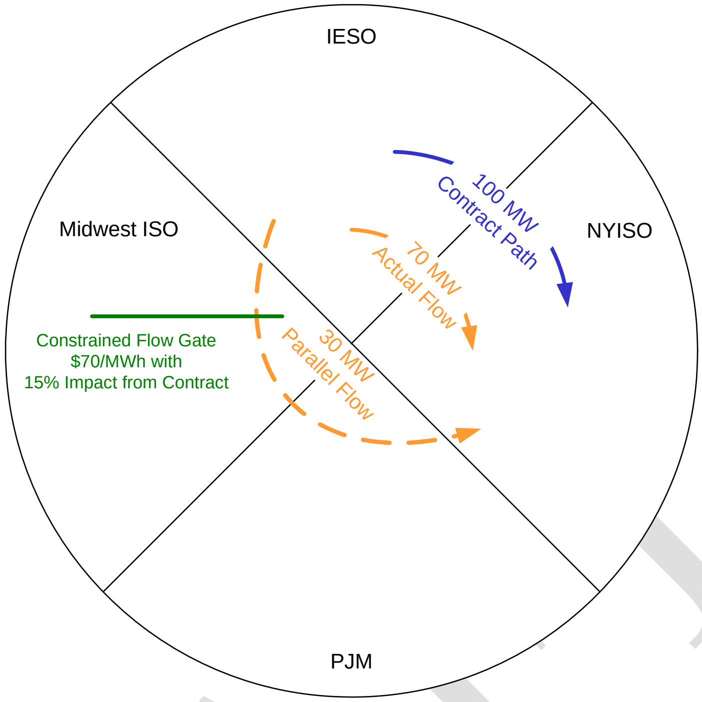


Figure 1. Congestion Charge Example.

x. Paying for Congestion Twice

From the congestion charges example, it would seem that the contract owner is double paying for the congestion that was created by the contract. This assertion is false and can best be illustrated with the example below.

Today, the Balancing Authorities security constrained dispatches already capture the impact of parallel (loop) flow when calculating the flowgate overload. The parallel (loop) flows are captured by representing the actual transmission flows within the dispatch.

Depending on the direction of parallel flow, these flows can reduce or increase the congestion on a flowgate. When calculating the flowgate overload (constraint), the calculation nets the forward flows and reverse flows to establish the net flowgate overload (severity of the constraint). The effect of netting the forward and reverse flows on a flowgate is carried through to the calculation of the shadow cost of the constraint. Therefore, when a transaction is not delivered 100% on contract path due to parallel (loop) flows and there is a constraint that separates the contract path from the parallel path (see figure below) the congestion charges for that constraint are reduced by the amount of parallel (loop) flow.

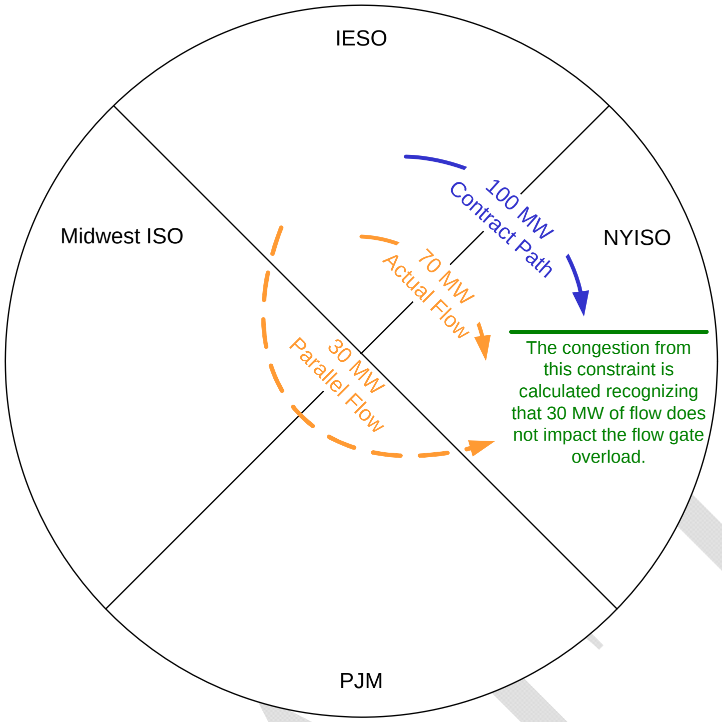


Figure 2. Paying for Congestion Twice Example.

<u>Example</u>

A market participant enters into a contract to buy 100 MW of energy from a source located within the Independent Electric System Operator (IESO) and sell the 100 MW of energy to a location within the New York Independent System Operator (NYISO). We will refer to the 100 MW contract as having a contract path from IESO to NYISO.

During the dispatch hour, the following conditions exist for only one five minute interval during an hour:

(1) The amount of parallel flow is 30 MW, while the amount of direct flow is 70 MW; and
(2) NYISO has a constrained flowgate that separates the contract path from the parallel path.

For the scenario described above, the 30 MW of parallel (loop) flow does not impact the constrained flowgate within the NYISO transmission system. This produces a reduced congestion cost (and ultimately reduced LMPs) to solve the constrained flowgate.

<u>Now consider the scenario without the parallel (loop) flow</u>
If the parallel (loop) flow did not exist, then an additional 30 MW of generation would have needed to be dispatched downstream of the constraint in order to prevent an overload. The dispatching of the additional 30 MW of generation downstream of the constraint would have required an equal reduction of generation upstream of the

constraint. This reduction in generation upstream of the constraint would have been represented as a reduction in LMP at the source of the contract.

By reflecting the actual flows when calculating the cost of congestion for the constraint, the calculated LMP at the source of the contract path is generally higher with the presence of parallel (loop) flow than without.

Similarly stated, the LMP at the source of the contract path would have been lower but for the presence of parallel (loop) flow which may have resulted in creating congestion in another Balancing Authorities area.

Conclusion

Therefore, the LMP with no parallel (loop) flow would have resulted in the contract path fully paying for congestion and the LMP with parallel (loop) flow would have resulted in the contract path paying a reduced amount of congestion.

Although congestion in the NYISO was reduced with the existence of parallel (loop) flow, the parallel (loop) flow may have caused or exacerbated congestion in the Midwest ISO or PJM Interconnection. This additional congestion cost is not captured in the congestion already charged to the contract path by the NYISO and currently no mechanism exists for the Midwest ISO or PJM Interconnection to recover the additional cost of congestion caused by parallel (loop) flow.

The Buy-Through of Congestion product creates the mechanism for all of the Balancing Authorities, affected by Lake Erie parallel (loop) flow, to recover this additional congestion cost caused by parallel (loop) flows associated with transaction contracts around Lake Erie.

xi. Settlement of Allocated Costs

The Monitoring ISO will be responsible for determining the congestion cost allocations to assign to the schedules based upon the information contained in the Parallel Flow Visualization tools and its own LBMP, or equivalent, calculations. The IDC will identify the MW impacts associated with transaction schedules. The LBMP calculations will capture the congestion costs incurred in addressing system constraints. Intra-control area generation-to-load impacts will not be included in the assignment of buy-through of congestion costs. Normal flow conditions from generation-to-load impacts are expected under interconnected system operation. Congestion Management protocols will be available to address the impacts created by generation-to-load impacts on flowgates in neighboring control areas.

Once calculated, the Buy-Through of Congestion charges will be processed to the transaction scheduler in a two step process whereby:

(1) The Monitoring ISO provides the charges to the Responsible Control Area(s);
(2) The Responsible Control Area applies the assigned charges to the specific transactions identified by the market flow calculation and collects the revenue from the identified billing organizations through normal billing procedures.

The Responsible Control Area(s) subsequently provides the collected funds to the Monitoring ISO (i.e. off-contract path impacted region.)

All associated buy-through of congestion charges collected by the Responsible Control Area are passed through to the affected off-contract path Monitoring ISOs. No payment to the off-contract path Monitoring ISOs is made in advance of the collection of charges from the scheduling entities, nor is any financial obligation placed on the Responsible Control Area(s) to cover the allocated charges for failures of a transaction party to pay their invoiced charges. Failure of a party to pay for the Buy-Through of Congestion portion of their settlements will be treated as a default with the ISO performing the billing.

All charges associated with buy-through of congestion allocations from the off-contract path region to the Responsible Control Area will be identified in US Dollars.

xii. Payment for Congestion Relief

Off-contract path flows which are having a counterflow impact on (relieving) prevailing flows will result in lower net flows on flowgates and reduced congestion management costs. To the extent that counter-flow off-contract path flows allow for a greater volume of off-contract path forward flow impacts to be managed, then the counter-flow transactions will be compensated at the same rate as the forward flow off-contract path impacts are charged. The total compensation paid to counter-flow transactions will not exceed the revenue received from forward flow impact schedules as calculated by the Monitoring ISO. All compensation payments would be calculated by the Monitoring ISO using the Monitoring ISO's billing rules or philosophies.

After successful implementation of the provisions, the ISOs will monitor the congestion cost charges from, and the congestion relief payment to off-contract path flows. The ISOs will evaluate based upon the successful demonstration of the ability to identify the collection of schedules having forward and counter-flow impacts, as well as the observed revenue sufficiency of congestion management cost recovery, if the limitation on payments for congestion relief can be eliminated.

Alternatively, a trader may explicitly represent those schedules in the relevant market that are expected to benefit from the congestion relief that the transactions will provide. By scheduling a transaction in the appropriate direction, the scheduled transaction will be explicitly settled within that market for the relief provided

c. Congestion Management

A highly interconnected transmission network provides benefits of improved operational reliability and redundancy. However, a necessary byproduct of synchronously interconnected control areas are loop flows resulting from a regions dispatch of its resources to meet its own load requirements. While loop flows can cause or aggravate constraints in a neighboring control area, the synchronous interconnection of neighboring markets also presents the opportunity for multiple control areas to act to relieve transmission congestion on the interconnected system.

The re-dispatch of generators within a control area that is interconnected with the control area that is experiencing the congestion may address transmission constraints more cost effectively than the re-dispatch of generators or other control action within the congested control area. A congestion management protocol allows for inter-control area dispatch to manage congestion (if and to the extent a neighboring control area can re-dispatch resources to alleviate the congestion at a lower cost than the control area that is experiencing the congestion), and permits the appropriate settlement of those actions.

In order to effectively implement congestion management it is necessary to pre-identify constraints that multiple control areas can address through re-dispatch actions, to develop an agreed to baseline of allowable usage of each others transmission networks, and to establish a data sharing protocols to communicate real-time constraint management costs between control areas. After-the-fact calculation of settlement charges will be performed to provide compensation for the dispatch action when the system flows are less than the pre-defined baseline values. Overuse of neighboring control area transmission systems must be redressed at a control areas own cost. Congestion Management will be incorporated directly into a regions dispatch and price setting protocols to maintain the existing consistency between resource schedules and prices. No other explicit charge or refund is necessary to a specific resource.

Congestion Management can achieve a more cost effective utilization of the regions collective assets to address constraints across multiple systems, resulting in lower congestion costs to consumers and provides a more consistent price profile across markets. The Congestion Management details currently being considered and described below are largely based on the existing Market-to-Market coordination program that is currently in place between the Midwest ISO and PJM.

i. Flowgate Identification

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize flowgates in various capacities to coordinate operations and manage reliability. Flowgates to be included in this congestion management program are determined through a series of studies designed to group flowgates into three categories. The three categories of flowgates are as follows:

1. AFC Flowgates
2. Coordinated Flowgates (CFs)
3. Reciprocal Coordinated Flowgates (RCFs).

An AFC flowgate is any flowgate for which an entity calculates an Available Flowgate Capability value.

A Coordinated Flowgate (CF) is a flowgate impacted by an Operating Entity as determined by one of four studies. Coordinated Flowgates are identified to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the congestion management processes and/or Reciprocal Operations.

A Reciprocal Coordinated Flowgate (RCF) refers to a flowgate that is subject to reciprocal coordination by Operating Entities between one or more Parties and one or more Third Party Operating Entities.

A RCF is:

1. A CF that is (a) (i) within the operational control of Reciprocal Entity or (ii) may be subject to the supervision of Reciprocal Entity as Reliability Coordinator, and (b) affected by the transmission of energy by two or more Parties; or
2. A CF that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to CMP reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
3. A CF that is designated by agreement of both Parties as an RCF.

In order to coordinate congestion management on a proactive basis, Operating Entities may agree to respect each other's flowgate limitations during the determination of AFC/ATC and the calculation of firmness during real-time operations. Entities agreeing to coordinate this future-looking management of Flowgate capacity are Reciprocal Entities. The Flowgates used in that process are Reciprocal Coordinated Flowgates.

Reciprocal Coordinated Flowgates are associated with the implementation of a Reciprocal Coordination Agreement between two Reciprocal Entities. By virtue of having executed such an agreement, a Flowgate Allocation can occur between these two Reciprocal Entities as well as all other Reciprocal Entities that have executed Reciprocal Coordination Agreements with at least one of these two Reciprocal Entities. When considering an implementation between two Reciprocal Entities, it is generally expected that each of the Reciprocal Coordinated Flowgates will meet the following three criteria:

- It will meet the criteria for Coordinated Flowgate status for both the Reciprocal Entities,

- It will be under the functional control of one of the two Reciprocal Entities and

- Both Reciprocal Entities have executed Reciprocal Coordination Agreements either with each other or with a third party Reciprocal Entity.

Disputed Flowgates

If a Reciprocal Entity believes that another Reciprocal Entity implementing the congestion management portion of this process has a significant impact on one of their Flowgates, but that Flowgate was not included in the Coordinated Flowgate list, the involved Reciprocal Entities will use the following process.

- If an operating emergency exists involving the candidate Flowgate, the Reciprocal Entities shall treat the facilities as a temporary Coordinated Flowgate prior to the study procedure below. If no operating emergency or imminent danger exists, the study procedure below shall be pursued prior to the candidate Flowgate being designated as a Coordinated Flowgate.

- The Reciprocal Entity conducts studies to determine the conditions under which the other Reciprocal Entity would have a significant impact on the Flowgate in question. The Reciprocal Entity conducting the study then submits these studies to the other Reciprocal Entity implementing this process. The Reciprocal Entity's studies should include each of the four studies described above; in addition to any other studies they believe illustrate the validity of their request. The other Reciprocal Entity will review the studies and determine if they appear to support the request of the Reciprocal Entity conducting the study. If they do, the Flowgate will be added to the list of Coordinated Flowgates.

- If, following evaluation of the supplied studies, any Reciprocal Entity still disputes another Reciprocal Entity's request, the Reciprocal Entity will submit a formal request to the NERC Operations Reliability Subcommittee (ORS) asking for further review of the situation. The NERC ORS will review the studies of both the requesting Reciprocal Entity and the other Reciprocal Entity, and direct the participating Reciprocal Entities to take appropriate action.

Frequency of Coordinated Flowgate Determination

The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then as requested by another reciprocal entity.

Dynamic Creation of Coordinated Flowgates

For temporary Flowgates developed "on the fly," the IDC will utilize the current IDC methodology for determining NNL contribution until the Market-Based Operating Entity has begun reporting data for the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will use reasonable effort to study the Flowgate in a timely manner and begin reporting flowgate data within two business days (where the flowgate has already been designated as an AFC Flowgate). This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the four studies detailed earlier in this document and determine the flowgate's relationship with the Market-Based Operating Entity's dispatch. For internal flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Market Flows; during a TLR 5, the IDC will request NNL relief in the same manner as today. Alternatively, for internal and external flowgates, an Operating Entity may utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary flowgate's monitored element and with the same contingent element. If the flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entities will coordinate respective actions to provide immediate relief until final review.

ii. Market Flow Calculation

(See description available in section 4.a)

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation, and be used in concert with the previously calculated Firm Flow Limits to determine the portion of those flows that should be considered firm and non-firm.

Every fifteen minutes, the Market-Based Operating Entity will be responsible for providing to Reliability Coordinators the following information:

- Firm Market Flows for all Coordinated Flowgates in each direction
- Non-Firm Market Flows for all Coordinated Flowgates in each direction

The Firm Market Flow (Priority 7-FN) will be equivalent to the calculated Market Flow, up to the Firm Flow Limit. In real time, any Market Flow in excess of the Firm Flow Limit will be reported as Non-Firm Market Flow (Priority 6-NN) (note that under reciprocal operations, some of this Non-Firm Market Flow may be quantified as Priority 2-NH).

This information will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the amount of flows to be considered firm on the various Coordinated Flowgates in each direction. When the Firm Flow Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual Firm Flow Limit (used in TLR5) will be set equal to Market Flow.

Additionally, every hour the Market-Based Operating Entity will submit to the Reliability Coordinator a set of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Day-Ahead Operations Process

The Market-Based Operating Entities will use a day-ahead operations process to establish the Firm Flow Limit on Coordinated Flowgates. If the Market-Based Operating Entities utilize a day-ahead unit commitment, they will supplement the day-ahead unit commitment with a security constrained economic dispatch tool, which uses a network analysis model that mirrors the real-time model found within their state estimators. As such, the day-ahead unit commitment and its associated Security Constrained Economic Dispatch respects facility limits and forecasted system constraints. Facility limits of Coordinated Flowgates under the functional control of Market-Based Operating Entities and the allocations of all Reciprocal Coordinated Flowgates will be honored.

For Coordinated Flowgates, a Market-Based Operating Entity can only use one of the following two methods to establish Firm Flow Limit. A Market-Based Operating Entity must use either the day-ahead unit commitment and its associated Security Constrained Economic Dispatch, or a Market-Based Operating Entity's GTL and unused Firm Transmission Service impacts, up to the Flowgate Limit, on the Coordinated Flowgate. At any given time, an entity must use only one method for all Coordinated Flowgates and must give ninety days notice to all other Reciprocal Entities, if it decides to switch from one method to the other method. On a case by case basis, with agreement by all Reciprocal Entities the ninety-day notice period may be waived.

Real-time Operation Process for Operating Entity Capabilities

Operating Entities' real-time EMS's have very detailed state estimator and security analysis packages that are able to monitor both thermal and voltage contingencies every few minutes. State estimation models will be at least as detailed as the IDC model for all the Coordinated and Reciprocal Coordinated Flowgates. Additionally, Reciprocal Entities will be continually working to ensure the models used in their calculation of Market Flow are kept up to date.

The Market-Based Operating Entities' state estimators and Unit Dispatch Systems (UDS) will utilize these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows (i.e., total Market Flows, Non-Firm Market Flows, and Firm Market Flows) on the Coordinated Flowgates. Using real-time modeling, the Market-Based Operating Entity's internal systems will be able to more reliably determine the impact on Flowgates created by dispatch than the NERC IDC. The reason for this difference in accuracy is that the IDC uses static SDX data that is not updated in real-time. In contrast to the SDX data, the Market-Based Operating Entity's calculations of system flows will utilize each unit's actual output, updated at least every 15 minutes on an established schedule.

Market-Based Operating Entity Real-time Actions

Market-Based Operating Entities will have the list of Coordinated Flowgates modeled as monitored facilities in its EMS. The Firm Flow Limits a Market-Based Operating Entity will use for these Flowgates will be the Firm Flow Limits determined by the Firm Market Flow calculations.

The Market-Based Operating Entity will upload the real-time and one-hour ahead projected Firm Market Flows (7-FN) and Non-Firm Market Flows (6-NN) on these Flowgates to the IDC every 15 minutes, as requested by the NERC IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). Market Flows will be calculated, down to five percent, and uploaded to the IDC. When the real-time actual flow exceeds the Flowgate limit and the Reliability Coordinator, who has responsibility for that Flowgate, has declared a TLR 3a or higher, the Market-Based Operating Entity will redispatch its system to the amount required by the IDC. The amount of redispatch will be calculated by the IDC. In a TLR 3, the Market-Based Operating Entity could be required to redispatch to the full amount of Non-Firm Market Flow over the Firm Flow Limit. Note the Market-Based Operating Entity may provide relief through either: (1) a reduction of flows on the Flowgate in the direction required, or (2) an increase of reverse flows on the Flowgate.

Market-Based Operating Entities will implement this redispatch by binding the Flowgate as a constraint in their Unit Dispatch System (UDS). UDS calculates the most economic solution while simultaneously ensuring that each of the bound constraints is resolved reliably. Additionally, the Market-Based Operating Entity will make any point-to-point transaction curtailments as specified by the NERC IDC.

A Market-Based Operating Entity's redispatch and relief time will be faster than the 30 minutes required by TLR schedule curtailments, because when the bounds are applied, the systems are designed to provide relief within 15 minutes.

The Reliability Coordinator calling the TLR will be able to see the relief provided on the Flowgate as the Market-Based Operating Entity continues to upload its contributions to the real-time flows on this Flowgate.

iii. Entitlements

Firm Flow Determination

Firm Market Flows represent the directional sum of flows created by Designated Network Resources serving designated network loads within a particular market area. They are based primarily on the configuration of the system and its associated flow characteristics; utilizing generation and load values as its primary inputs. Therefore, these Firm Market Flows can be determined based on expected usage and the Allocation of Flowgate capacity.

An entity can determine Firm Market Flows on a particular Flowgate using the same process as utilized by the IDC. This process is summarized below:

1. Utilize a reference base case to determine the Generation Shift Factors for all generators in the current Control Areas' respective footprints to a specific swing bus with respect to a specific Flowgate.

2. Utilize the same base case to determine the Load Shift Factors for the Control Area's load to a specific swing bus with respect to that Flowgate.

3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for the generators with respect to that Flowgate.

4. Multiply the expected output used to serve native load from each generator by the appropriate GLDF to determine that generators flow on the Flowgate.

5. Sum these individual contributions by direction to create the directional Firm Market Flow impact on the Flowgate.

Determining the Firm Flow Limit

Given the Firm Market Flow determinations described in the previous section, Market-Based Operating Entities can assume them to be their Firm Flow Limits. These limits define the maximum value of the Market Flows that can be considered as firm in each direction on a particular Flowgate. Prior to real time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Market Flows. This is a significant improvement over current IDC processes, which uses a peak load value instead of an hourly load more closely aligned with forecasted data.

Firm Market Flow Calculation Rules

The Firm Flow Limits will be calculated based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC (but utilizing impacts down to five percent). The following points form the basis for the calculation.

1. The generation-to-load calculation will be made on a Control Area basis. The impact of generation-to-load will be determined for Coordinated Flowgates.

2. The Flowgate impact will be determined based on individual generators serving aggregated CA load. Only generators that are Designated Network Resources for the CA load will be included in the calculation.

3. Forward Firm Flow Limits will consider impacts in the additive direction down to 5% and reverse Firm Flow Limits will consider impacts in the counter flow direction down to 5%. Market Flow impacts and allocations using a zero percent threshold are determined for information reporting to the IDC.

4. Designated Network Resources located outside the CA will not be included in the generation-to-load calculation if OASIS reservations exist for these generators.

5. Generators that will be off-line during the calculated period will not be included in the generation-to-load calculation for that period.

6. CA net interchange will be computed by summing all Firm Transmission Service reservations and all Designated Network Resources that are in effect throughout the calculation period. Designated Network Resources are included in CA net interchange to the extent they are located outside the CA and have an OASIS reservation. The net interchange will either be positive (exports exceed imports) or negative (imports exceed exports).

7. If the net interchange is negative, the period load is reduced by the net interchange.

8. If the net interchange is positive, the period load is not adjusted for net interchange.

9. The generation-to-load calculation will be made using generation-to-load distribution factors that represent the topology of the system for the period under consideration.

10. PMAX of the generators should be net generation (excluding the plant auxiliaries) and the CA load should not include plant auxiliaries.

11. The portion of jointly owned units that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

iv. Settlement / Pricing

The Market Settlements under the coordinated congestion management will be performed based on the Real-Time Market Flow contribution on the transmission flowgate from the Non-Monitoring RTO as compared to its flow entitlement.

If the Real-Time Market Flow is greater than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Non-Monitoring RTO will pay the Monitoring RTO for congestion relief provided to sustain the higher level of Real-Time market flow. This payment will be calculated based on the following equation:

Payment = (Real-Time Market Flow MW1 – (Firm Flow Entitlement MW2 + Approved MW3)) * Transmission Constraint Shadow Price in Monitoring RTOs Dispatch Solution

If the Real-Time Market Flow is less than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Monitoring RTO will pay the Non-Monitoring RTO for congestion relief provided at a level below the flow entitlement. This payment will be calculated based on the following equation:

Payment = ((Firm Flow Entitlement MW2 + Approved MW3) – Real-Time Market FlowMW1) * Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution

For the purpose of settlements calculations, shadow prices will be calculated by the pricing software in the same manner as the LMP, and will be integrated over each hour during which a transmission constraint is being actively coordinated under the ICP by summing the five-minute shadow prices during the active periods within the hour and dividing by 12 (the number of five minute intervals in the hour).

d. Enhanced Interregional Transaction Coordination

i. Background

Today, the PJM Interconnection and the Midwest ISO provide the ability for market participants to enter into or back out of an energy transaction on a fifteen minute basis on most external interfaces. Additionally, the NYISO and IESO currently allows for hourly energy scheduling across the external interfaces.

For the NYISO, Enhanced Interregional Transaction Coordination will permit the scheduling of inter-control area transactions on a more frequent basis than the current hourly schedules. Flexible transaction scheduling provisions improve market and operational efficiency by allowing resources schedules to adjust to the dynamic changes in system conditions, as well as unexpected changes to projected conditions. Desired additional flexibility must be balanced with the operational benefits associated with defined firm energy delivery schedules.

Flexible transaction scheduling requires advancements to the existing processes for the development of transaction schedules and the protocols for validation of those schedules. The existing process lacks the coordination and automation necessary to support a scheduling frequency sufficient to address dynamic system conditions. Transaction schedules must be co-developed, rather than independently evaluated, to ensure both regions arrive at the same outcome and the same expectations for energy delivery or receipt. A new capability could be developed to schedule transaction based upon moving power between regions at defined price differences, whereby a participant would supply a single transaction request to be used by both regions indicating the transaction should be scheduled when the specified spread between the prices in the two regions is achieved. The regions would use expected prices to select transaction requests with lower bids than the predicted difference in market prices. The regions would incorporate the updated transaction schedules into the dispatch tools and repeat the process for the next scheduling horizon.

Interregional Transaction Scheduling is expected to lower total system operating costs through improved consistency of transaction schedules with market-to-market prices, to expand the pool of flexible assets that are available to balance intermittent power resources, to improve price consistency and transmission utilization and to address existing uncertainties in forward looking scheduling horizons.

ii. Bidding and Scheduling

It is envisioned that all transactions scheduled between Balancing Authorities would still follow all NERC electronic tagging requirements. For those market participants that wish to participate in more frequent scheduling, market participants would model their NERC electronic tag as a dynamic tag.

Hourly transaction or hourly dispatchable transactions are scheduled on an hourly basis by the Day Ahead or Real-Time scheduling systems where the transaction schedules can vary from hour to hour. Intra-hour transactions or intra-hour dispatchable transactions will have an hourly schedule which can vary from hour to hour in the Day Ahead Market, while the Real-Time Market may dispatch the transaction as frequently as every five minutes within an hour. Intra-hour transactions may only be import or export transactions, as wheel-through transactions will not be eligible for intra-hour transaction scheduling.

The bidding systems of the NYISO would continue to require a market participant to enter new hourly transactions into the real-time market at least seventy five minutes prior to the operating hour. Additionally, the NYISO bidding system could be modified to allow intra-hour transactions to be added, updated, or removed closer to the actual dispatch horizon. The purpose of the additional flexibility is to allow market participants to minimize buy-through of congestion exposure.

Depending on the NYISO border, Enhanced Interregional Transaction Coordination may take place on a five or fifteen minute basis. Fifteen minute transaction coordination would be used on borders where the NYISO must coordinate with other markets. Five minute transaction coordination would likely be used on borders where the scheduling interface is fully controllable via Variable Frequency Transformer or Direct Current technology.

To date, the NYISO has already begun developing a concept with Hydro Quebec where intra-hour transactions would be scheduled on a five minute basis. Advisory fifteen minute schedules with Hydro Quebec will be created by Real-Time Commitment (‘RTC’) and those schedules will be checked out with Hydro Quebec prior to the dispatch hour. During the dispatch hour, the Real-Time Dispatch (‘RTD’) or Real-Time Dispatch Corrective Action Mode (‘RTD-CAM’) will generate a five minute interchange with Hydro Quebec. The five minute interchange will be communicated to Hydro Quebec using Inter-Control Center Communications Protocol (‘ICCP’).

Additionally, the NYISO and PJM have begun working together to develop a concept for fifteen minute transaction scheduling. The NYISO intends to offer the flexibility for market participants to reduce or reinstate a transaction within the dispatch hour. The PJM Interconnection already offers their market participants this flexibility and has a fifteen minute transaction scheduling product in use with other neighbors today.

The NYISO anticipates that the Real-Time Dispatch would economically schedule the intra-hour transactions on a fifteen minute basis. These fifteen minute transaction schedules will be coordinated between PJM and NYISO via a fifteen minute checkout process where automation would be used to facilitate a timely checkout.

Finally, the NYISO intends to phase in this concept starting with each of the PJM-NY controllable tie lines followed closely by the broader NYISO/PJM interface.

iii. Settlement

The NYISO would continue to settle all hourly and intra-hour transaction on a five minute basis. When Enhanced Interregional Transaction Coordination is enabled at a scheduling location, hourly import transaction will no longer be eligible for real-time bid production cost guarantees.

Additionally to deter transaction failures for the sole purpose of increasing real-time LMPs, the NYISO will continue to charge transactions a penalty known as the Financial

Impact Charge ('FIC'). The FIC is determined by calculating the impact failed transaction had on LMPs using the average RTC LMP as the reference.

e. <u>Market Modeling</u>

i. Interface Proxy Price Determination

Interface proxy bus pricing methodologies utilized across the region need to be carefully understood to ensure the compatibility of the methodologies employed. Efficient and compatible interface proxy bus prices will result in desired and anticipated market response to transfer power among the region. To improve the efficiency of the interface proxy bus pricing results, several developments need to occur to address interface pricing for both the current situation of power control device installations as well as future installations and operations of power control devices.

In recognition of the overall objective of harmonizing the market rules across the region, as well as the current lack of a clear schedule for the implementation and operation of the Ontario – Michigan Phase Angle Regulators to control Lake Erie loop flow, the NYISO will pursue modifications to its interface pricing methodology. As such the NYISO will engage its stakeholder community to adjust the interface price methodologies to:

- Recognize the incremental distribution of power flows around Lake Erie when evaluating and pricing the marginal impacts of transaction and generation schedules;
- Evaluate the need for and scheduling rules surrounding establishing an additional proxy bus location for the MISO to acknowledge power deliveries from or to the Midwest region;
- Evaluate the continued applicability of the existing circuitous path prohibitions.

Additionally, the ISO/RTOs recognize the importance of maintaining compatible and efficient interface proxy bus prices when the PARs on the Ontario – Michigan border are ultimately installed and available for remediation of Lake Erie loop flows. These devices have the ability to redirect the flow of power and adjust the actual power deliveries to be more consistent with contract path, or bid path, intentions. The regions existing interface proxy bus pricing methodologies may not be compatible with all operating scenarios and may need either additional pricing points to be created, interface price weighting associated with current points adjusted or adjustments to incremental distribution of power flows to acknowledge contract path flows to reflect actual operating scenarios. The interface proxy price methodologies will again need to be revised to reflect:

- The state of control of the Phase Angle Regulators to manage Lake Erie loop flows.
    - o Under Lake Erie loop flow controlled operation, the actual delivery of power and pricing methodologies will reflect contract path, or bid path, as is currently reflected in the NYISO and IESO implementations.

    - Under uncontrolled Lake Erie loop flow operation, the interface proxy price methodologies will need to reflect the revised power deliveries.
- Evaluate the revisions necessary to extend tag-based pricing to incorporate contract path deliveries;
- Evaluate the location(s) established for proxy price determination;
- Evaluate the ability to predict the controllability of the Phase Angle Regulators to manage Lake Erie loop flows to incorporate the necessary assumptions into the respective Day-Ahead markets and Hour-Ahead markets.

ii. Additional NYISO-PJM Interface Pricing Points

At the present time, there are three pricing points between the transmission interface between the New York Independent System Operator (NYISO) and PJM Interconnection (PJM). One interface pricing point is for the larger AC interconnected interface between NYISO and PJM with the other interface pricing points being located at the Neptune DC interconnection between NJ and Long Island, NY and the Linden VFT interconnection between NJ and NYC. Market participants have expressed a desire to see additional pricing points established on the interface between NYISO and PJM.

Traditionally, additional pricing points along a free-flowing AC interface have provided market participants with the ability to game that interface through transaction scheduling activities. This type behavior is difficult for transmission providers to easily identify and curtail scheduled transactions that contribute to loop flows in real-time market operations. NYISO and PJM staffs currently believe that the creation of additional pricing points on the overall AC interface would create opportunities for gaming this interface in a detrimental manner and would result in increased loop flows around Lake Erie.

The deployment of new technologies such as Variable Frequency Transformers (VFTs) may provide the ability to completely control scheduled flows across an additional interface. NYISO and PJM staffs believe it may be possible to establish additional pricing points for these devices if it can be established that the requisite control capability exists to prevent the introduction of additional loop flow impacts. The potential for establishing new pricing points for such facilities will be evaluated by the staffs at NYISO and PJM going forward.

f. <u>Dispute Resolution</u>

Parties to this effort will require access to pre-defined dispute resolution protocols to ensure maters of disagreement can be promptly and efficiently addressed. Dispute resolution procedures current exist between PJM and MISO in their Congestion

Management Protocol. See Article XIV of the PJM and MISO joint operating agreement.[4]

There are also dispute resolution protocols in existing inter-control area operating agreements that could be of use in developing acceptable dispute resolution procedures[5]

These existing agreements will be used as sources to develop a new multi-ISO dispute resolution agreement. Effective dispute resolution protocols are necessary for the successful implementation of the Buy-Through of Congestion solution. The new agreement will need to appreciate that FERC jurisdiction only applies to MISO, PJM and NYISO.

Filename: Broader Regional Markets White Paper v16.doc

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[4] http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-76d90a48324a

[5] http://www.nyiso.com/public/documents/regulatory/agreements.jsp

Attachment B

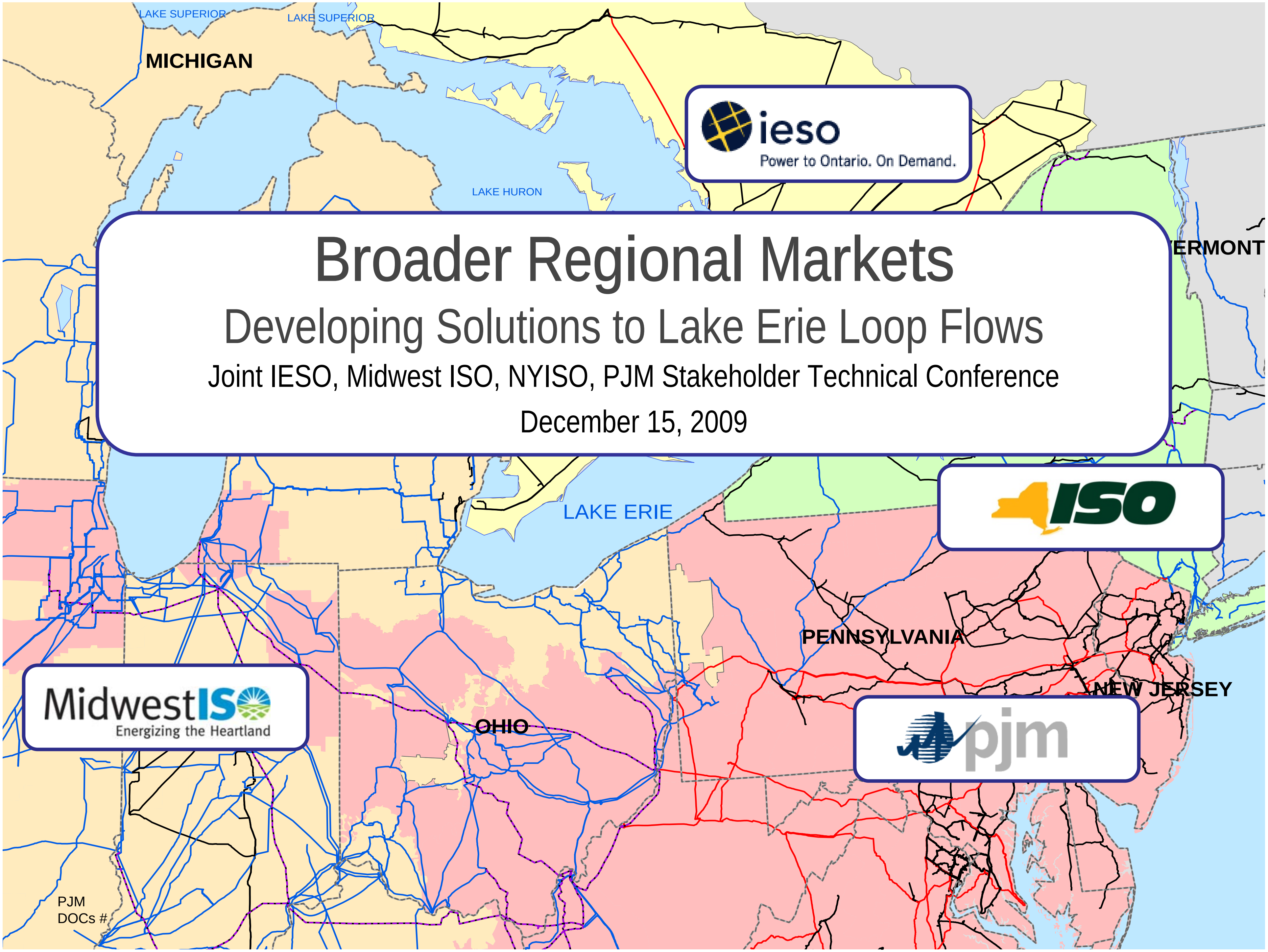
Broader Regional Markets, Long-Term Solutions to Lake Erie Loop Flow Slide Presentation from the December 15, 2009 Technical Conference Held in Carmel, Indiana

Broader Regional Markets

Developing Solutions to Lake Erie Loop Flows

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



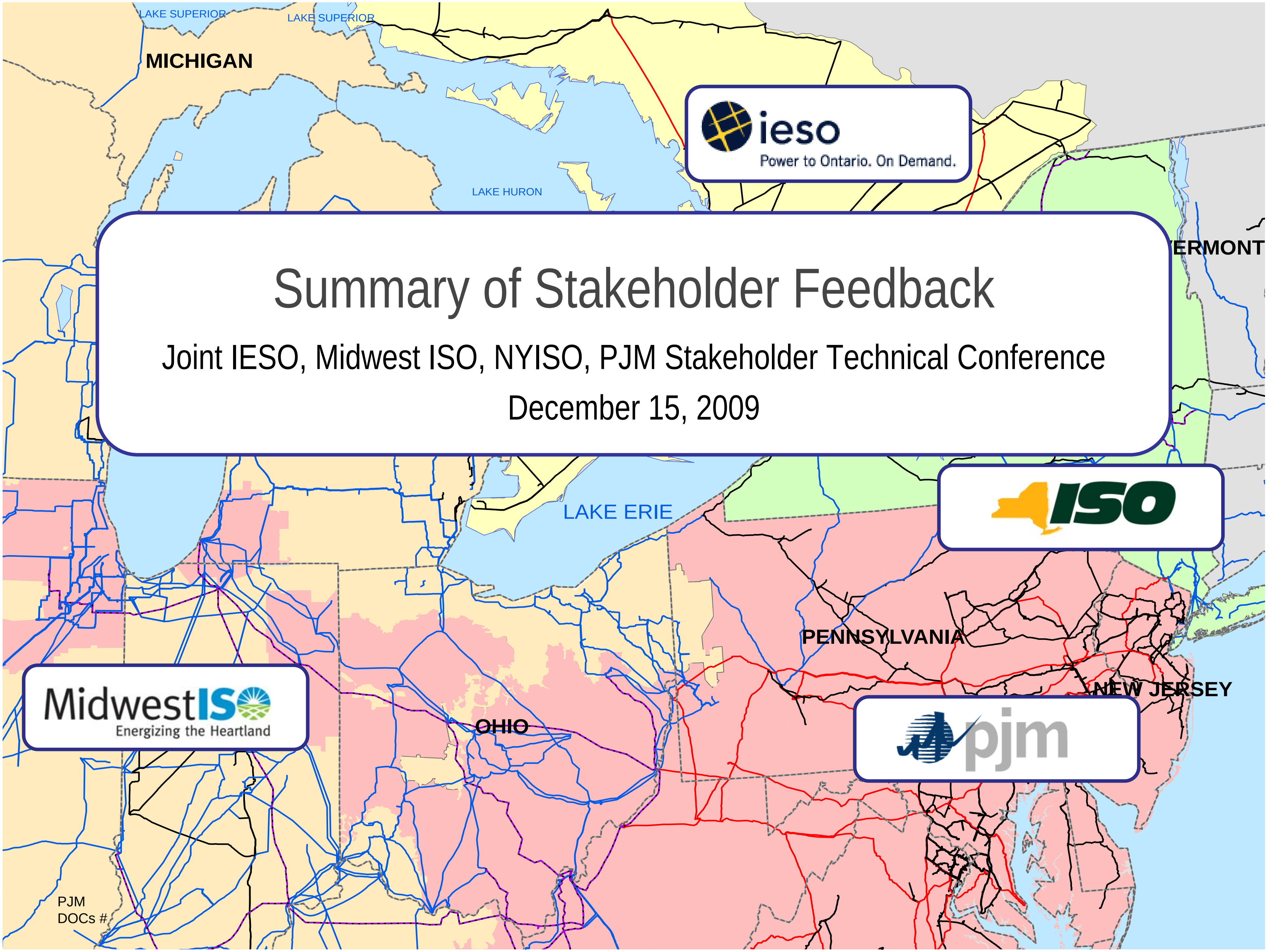
Agenda

- Welcome
- Summary of Stakeholder Feedback
- Recommended Solution Review
- Proposal Updates
  - Increased Coordination
  - Buy-Through of Congestion Update
  - Interface Pricing Update
  - Enhanced Interregional Transaction Coordination
- Parallel Flow Visualization Update
- Next Steps
  - Potential Implementation Timeline
  - January FERC Report
  - Ongoing Efforts

Summary of Stakeholder Feedback

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



Summary of Feedback

- Feedback was received by 11 stakeholders on the Broader Regional Markets Solutions to Loop Flow Whitepaper and Presentations
- Feedback generally grouped as follows:
  - Absent/Deficient
  - Buy-Through
  - Cost/Benefit
  - Physical Solutions
  - Flow Visualization
  - Interregional Transactions
  - Implementation
  - Miscellaneous

Absent/Deficient Comments

- Need better coordination of transmission service between ISO/RTO organizations surrounding Lake Erie
- ATC/AFC calculation and coordination efforts need to be improved to avoid over-selling transmission
- A common interface pricing methodology needs to be put in place by all ISO/RTO organizations surrounding Lake Erie

Buy-Through Congestion

- Hedging instruments
- Credit for congestion relief
- Transaction scheduling options to avoid buy-through congestion charges
- Status of firm service customers rejecting buy-though effectively become non-firm
- Potential to double-charge for congestion
- Contract path entities charges based on real, not scheduled, power flow
- Not a market-based solution
- Potential for market manipulation
- Should include an "up-to" congestion charge option
  - May be possible as seams disappear
- Should compensate for counter-flow transactions
- Bill transactions up to point of curtailment similar to NYISO non-firm transactions

Cost/Benefit

- Estimate resource costs of each proposed solution
- Indication that customers will use buy-through congestion needs to be provided in order to justify development and implementation costs
- Concern expressed that solutions options will require a significant amount of staff resources and capital to implement

Physical Solutions

- General support for installation and operation of the PARs on the Michigan-Ontario Interface
- PARs will not solve market pricing issues
- PARs will improve the ability to control actual power flows to scheduled flows
- PARs may increase actual energy flows south of Lake Erie
- All physical devices are part of the solution to address Lake Erie Loop Flows
- Coordination of all PARs surrounding Lake Erie deemed necessary to control Lake Erie Loop Flows
  - Impact to the Public Service – Consolidated Edison Wheeling Agreement
- Michigan consumers bear the bulk of the PAR devise costs while others receive benefits

Flow Visualization

- Flow visualization should not be linked with the required compliance filing
- Seen as a long overdue upgrade
- Expand to include all ISO organizations in regional footprint

Interregional Transactions

- More detail needed on interregional transaction coordination

Implementation

- Improve interface pricing before implementing buy-through of congestion
- Use Midwest ISO/PJM interface pricing methodology
- Hold mandatory progress status update meetings with stakeholders
- Impacts of staggered implementation
- Implement congestion management before buy-through of congestion

Miscellaneous

- Additional transmission facilities, such as transmission lines, are needed

Thanks

- Thanks to all of you that took the time to provide comments
- All comments were reviewed and discussed as some length
- Comments and feedback have been posted at the following web location: http://www.midwestiso.org/publish/Folder/4dfde8_124a04ca493_-7c8e0a48324a
- Additional feedback requested and welcome

Recommended Solution Review

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009

Concept Development

- Stakeholder meetings to review background issues and solutions to loop flow concepts.
- Joint ISO Meetings
  - Senior level scope reviews and updates
  - Weekly conference calls and additional in-person meetings to develop concepts of buy-through of congestion and congestion management as well as potential timeline.
- Joint Stakeholder Technical Conference
- Broader Regional Markets Whitepaper describing proposed solutions

- Proposed Solutions to Loop Flows
  - Physical Solution
    - Installation and operation of the Michigan/Ontario PARs to better conform actual power flows to scheduled power flows
- Parallel Flow Visualization
- Market Solutions
  - Buy-Through of Congestion
  - Congestion Management (Market-to-Market Coordination)
  - Interregional Transaction Coordination

Solution Objectives

- Reduce need for, frequency of, and magnitude of Transmission Loading Relief (TLR) events to address loop flow.
  - Buy-Through of Congestion provides an alternative to market and operational interruptions caused by TLR events; establishes an economic based alternative to imposed curtailments.
- Align constraint management cost recovery with sources of flow
  - Parallel Flow Visualization and Buy-Through of Congestion facilitate identification of sources of loop flow and provide a mechanism to recover congestion management costs incurred to support loop flows.
- Reduce constraint management costs for consumers across region.
  - Congestion Management achieves a more cost effective utilization of the region's collective assets to address constraints across multiple systems.
- Improve regional price consistency and transmission utilization
  - Congestion Management expands asset pool to address regional constraints.
  - Interregional Transaction Coordination provides for the more frequent adjustment of interchange schedules in response to changing market conditions; expands pool of flexible assets to balance intermittent power resources output.

Physical Solutions to Loop Flows

- Some control of loop flow can be achieved through the use of physical devices such as phase shifting transformers, also know as phase angle regulators or PARs.
- Control of loop flows around Lake Erie will be improved with the completed installation of the Ontario-Michigan PARs.
  - The intent is to operate the Michigan-Ontario PARs so as to better match actual flows with the scheduled flows across the interconnection.
- Status of Michigan-Ontario PARs
  - Initial installation completed in 1999
  - Ongoing operation delayed due to equipment failures & difficulties in getting operating agreements in place
  - Failed equipment replaced and additional further protection upgrades scheduled to be in place by the end of Q1 2010
- Coordinated Operation of All Devices
  - It is important that the operation of such devices by the four markets around Lake Erie be coordinated to avoid detrimental impacts.

Parallel Flow Visualization

- Provides single common source and methodology for isolating sources of flow.
  - Identify sources of flowgate impact, included Balancing Authority to Balancing Authority interchange schedules, and intra-regional generation-to-load impacts.
  - Incorporates state of phase angle regulator controls.
  - Methodology defined at vetted in NERC working groups.
- Market visibility of impacts available through the NERC IDC or OATi tools.
- Loop flow impacts calculated by IDC will reflect the ability (or lack thereof) of the PARs to maintain actual flow consistent with scheduled flow.

Buy-Through of Congestion

- Benefits
  - Buy-Through of Congestion provides for the recovery of congestion management costs incurred in managing loop flow impacts.
    - Provides for an alternative to market and operational interruptions caused by Transmission Loading Relief (TLR) actions by establishing an economic based alternative to imposed curtailments.
    - More efficient utilization of the transmission network.
    - More consistent transaction scheduling decisions with regional prices.
- Concept
  - Parties scheduling transactions with any of the other ISO/RTOs surrounding Lake Erie would be billed for the real-time congestion costs incurred by neighboring systems supporting the loop flow created by the transaction to maintain the schedule.
    - Exposure to congestion costs can be hedged with existing Day-Ahead transmission scheduling processes, or avoided with real-time scheduling processes

Market-to-Market Coordination

- Benefits
  - Lower congestion cost: The redispatch cost for the market would have been higher if one RTO had to control all transmission constraints on its own.
  - More consistent pricing across the RTO border: When the market-to-market coordination is in effect, the prices at the border converge better than before.
  - More Reliable operation: Since economic generation in another RTO/ISO is now available for constraint control, the other should experience fewer emergency transmission operations.
- Concept
  - Achieve the least cost redispatch solution for coordinated constraints across multiple systems.
  - Provide a more consistent pricing profile across the two markets.
  - Enhance system reliability by pooling resources from both RTOs to jointly control transmission constraints near the RTO border.

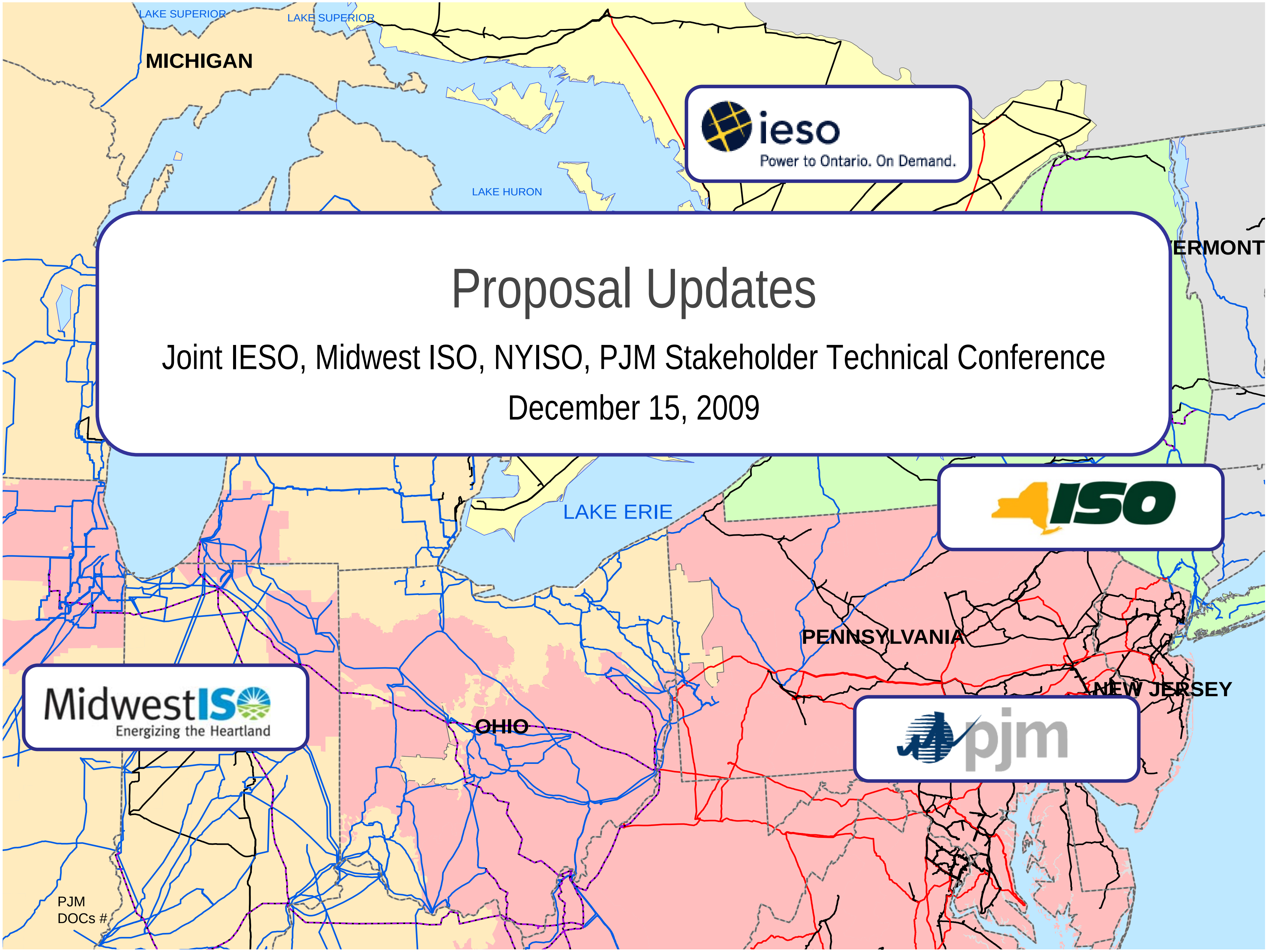
Interregional Transaction Coordination

- Benefits
  - In-hour transaction scheduling lowers total system operating costs through improved consistency of transaction schedules with market-to-market price patterns.
  - Expand pool of flexible assets to balance intermittent power resources output.
  - Improve price consistency and transmission utilization across markets.
  - Address uncertainty in forward looking scheduling horizons.
- Concept
  - Allow Market Participants to provide flexible energy, reserve and regulation transaction bids, where the real-time dispatch tools will evaluate these flexible transactions on an intra-hour basis.

Proposal Updates

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



Increased Coordination

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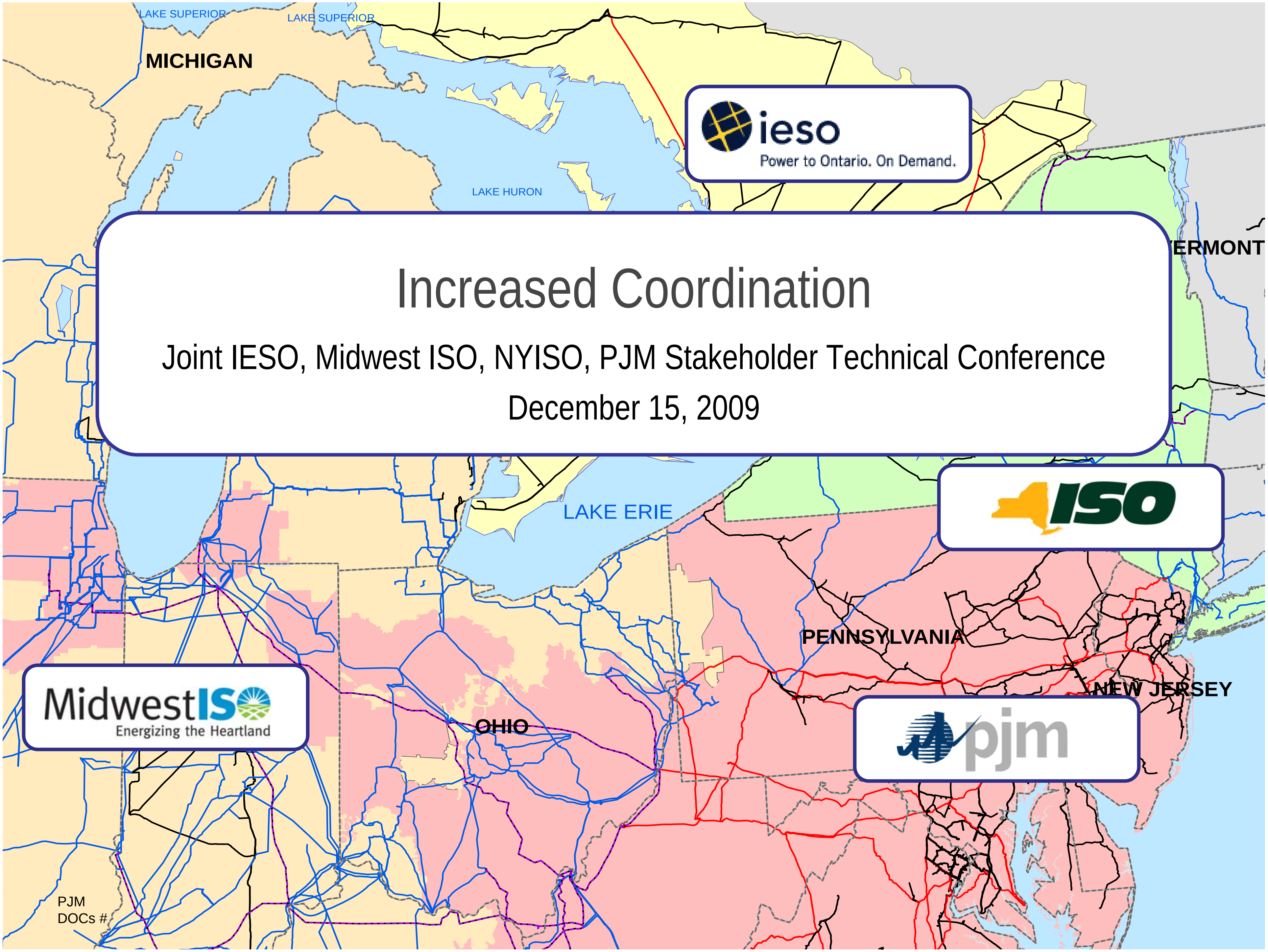
December 15, 2009



Stakeholder Feedback Summary

- Need better coordination of transmission service between ISO/RTO organizations surrounding Lake Erie
- ATC/AFC calculation and coordination efforts need to be improved to avoid over-selling transmission
- A common interface pricing methodology needs to be put in place by all ISO/RTO organizations surrounding Lake Erie

Current NYISO/PJM ATC/AFC Coordination Practices

- NYISO/PJM Joint Operating Agreement specifies the exchange of
  - Scheduled outage information for a minimum of 18 months
  - Interchange schedule information for use in calculation of TTC, ATC/AFV values
  - Transmission configuration changes
  - Generation additions and retirements
- Transmission system impacts are also coordinated as needed with other:
  - Reliability Coordinators
  - Balancing Authorities
  - Generator Operators
- Develop and implement action plans to mitigate potential or actual violations of:
  - Security Operating Limit (SOL)
  - Interconnection Reliability Operating Limit (IROL)
  - Control Performance Standard (CPS)
  - Disturbance Control Standard (DCS)

Current Midwest ISO/PJM ATC/AFC Coordination Practices

- Conducted in a similar manner to NYISO/PJM coordination practices described previously
- Additional calculations are performed to support the Congestion Management Process in place between the Midwest ISO and PJM
  - Calculation of Firm Flow Limits on Coordinated Flowgates
  - Directional market flow impacts on all Coordinated Flowgates
    - Determines the portion of flows in each direction considered Firm and Non-firm for both the current hour and next hour
  - Marginal units and associated participation factors for generation within the market footprint are provided at least quarterly to Reliability Coordinators
    - Determines the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area
- Congestion Management Process effectively extends the value of the TTC/ATC/AFC calculation process
  - Includes generation impacts on constrained flowgates
  - Maximized the use of constrained transmission facilities
  - Minimizes the need to use TLR to control transmission congestion created by loop flows

Additional ATC/AFC Coordination Practices

- Each ISO has established processes for approving firm transaction requests
- All transmission providers currently honor the physical capabilities of the transmission system surrounding Lake Erie prior to accepting a transmission service request

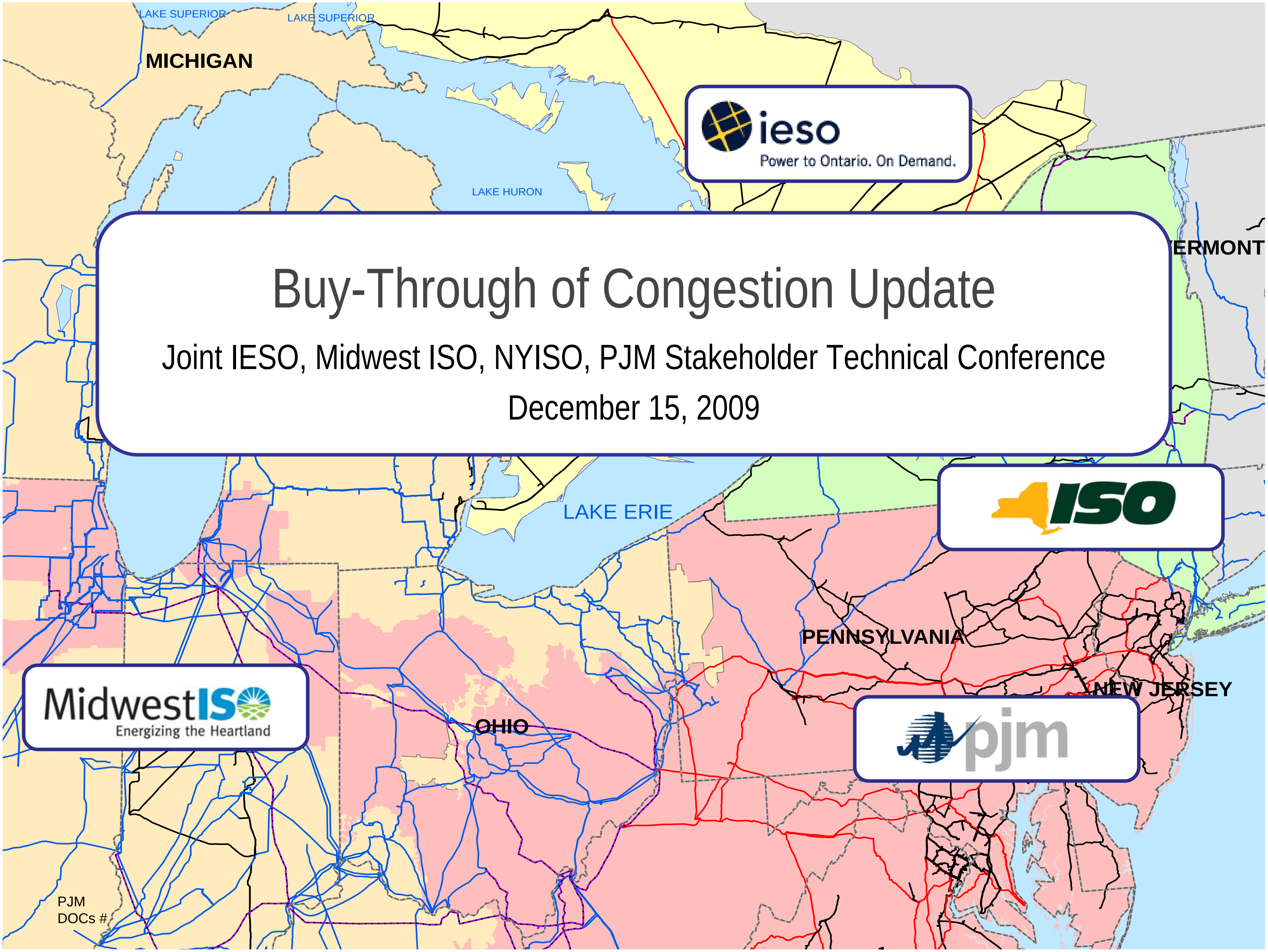
Increasing ATC/AFC Coordination

- Incremental improvements will not necessarily reduce loop flows around Lake Erie
- The development and implementation of a Congestion Management Process between all parties around Lake Erie will improve ATC/AFC coordination by
  - Including generation impacts on constrained flowgates
  - Maximizing the use of constrained transmission facilities
  - Minimizing the need to use TLR to control transmission congestion created by loop flows
- All parties surrounding Lake Erie will continue to look for additional opportunities to improve ATC/AFC coordination

Buy-Through of Congestion Update

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



Management of Congestion Cost Exposure

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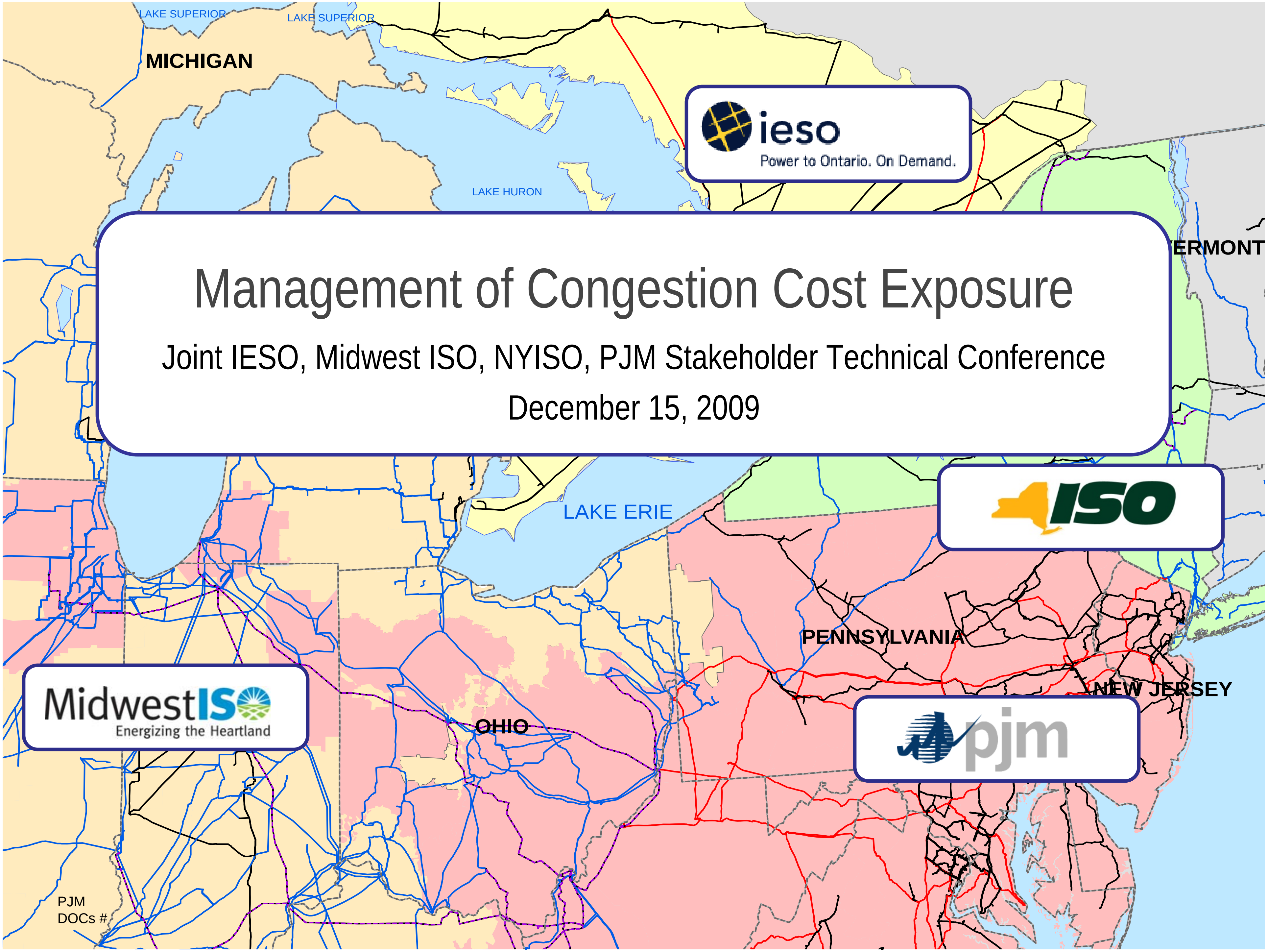
December 15, 2009



Stakeholder Feedback Summary

- Several parties have commented on the need for an up-to congestion option to provide a hedging opportunity to the cost exposure from parallel flow congestion charges.
- Concerns expressed with impact on trading volume in the absence of option.

Evaluation

- Existing transaction scheduling already involves evaluating
  - Price forecasts
  - Hedging opportunities
  - Cost exposures.
- Existing scheduling does not include automated price termination thresholds.
- Recognize that the buy-through of congestion provisions do result in a new cost exposure to transaction scheduling.
- However, consideration of this new exposure will parallel existing evaluations of contract path cost risks.

Hedging Options

- NYISO: Up-to congestion product available in DA. Opportunities to expand virtual trading to the proxy bus locations and virtual trading based upon price differences.
- PJM: Up-to congestion product available in DA. 20-minute notice schedule termination.
  Virtual bidding options available.
- MISO: Up-to congestion product available in DA.
  20-minute notice schedule termination.
  Virtual bidding options available.
- IESO: No products currently available.

Data Transparency

- In support of providing sufficient transparency of potential congestion cost charges, additional information will be available:
  - Flowgate Impacts
  - Constraint Shadow Costs
  - Observed Circulation
- Alternative solutions may be available from third party services based upon public data provided by IDC.

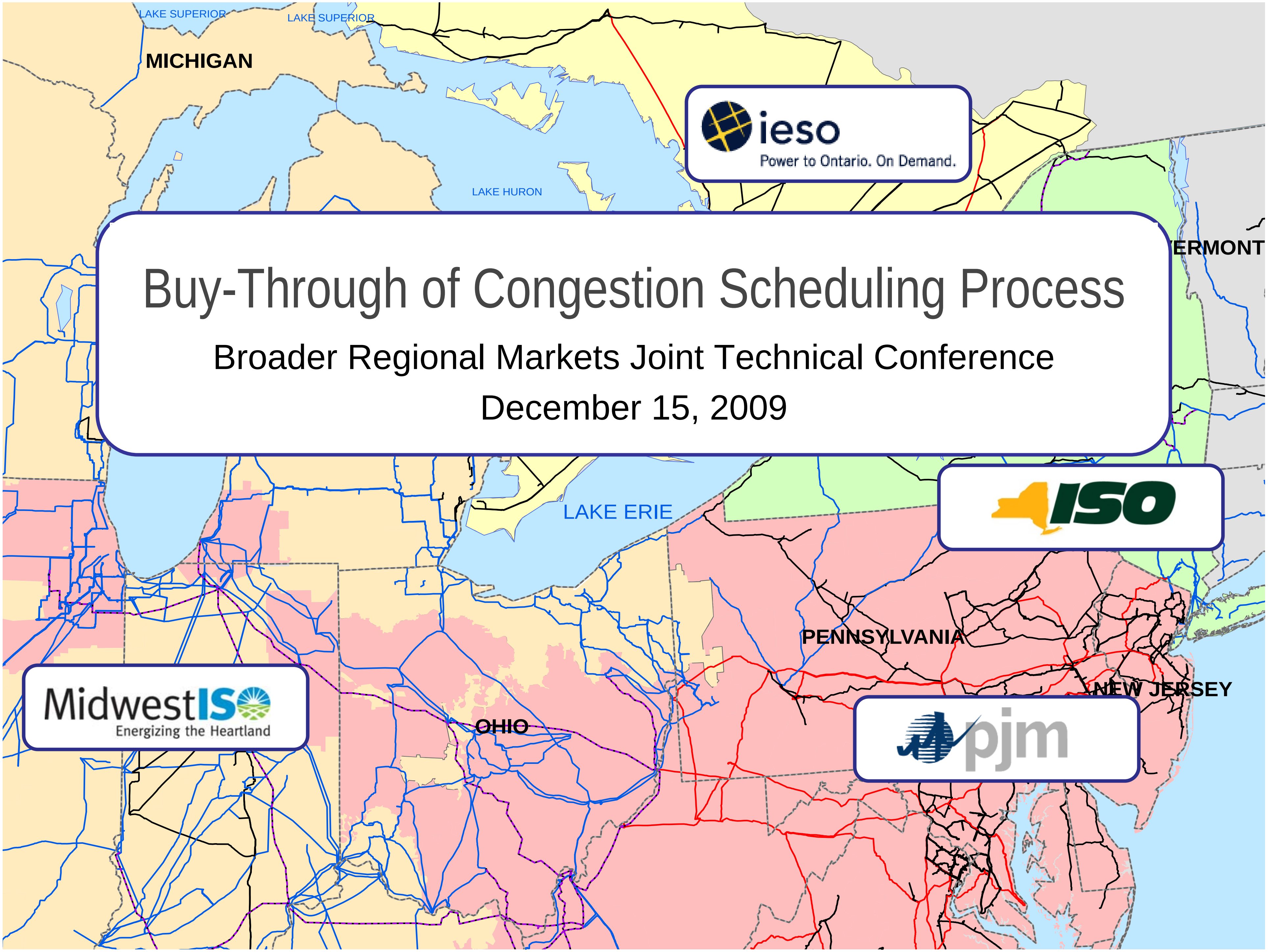
Summary

- Support provisions to ensure necessary data visibility and transparency of occurring and projected congestion costs to allow full consideration of the potential cost exposure, as well as availability of hedging products to allow traders to purchase congestion management service within the day-ahead markets.
- Capabilities will allow traders to manage cost exposure without the availability of an up-to product, consistent with existing cost risk management.

Buy-Through of Congestion Scheduling Process

Broader Regional Markets Joint Technical Conference

December 15, 2009



Scheduling Process Considerations

- Initiated during the hour ahead [*Allows the balancing authority to plan its way into reliable real-time operation*]
- TLR timing and procedures take priority and must not be compromised by buy-through of congestion provisions [*Allows TLRs to be called in a timely manner*]
- There is no distinction between firm and non-firm transmission transactions within the Buy-Through of Congestion process *[Willingness to pay (off-contract path) congestion costs not linked to transmission service selected.]*

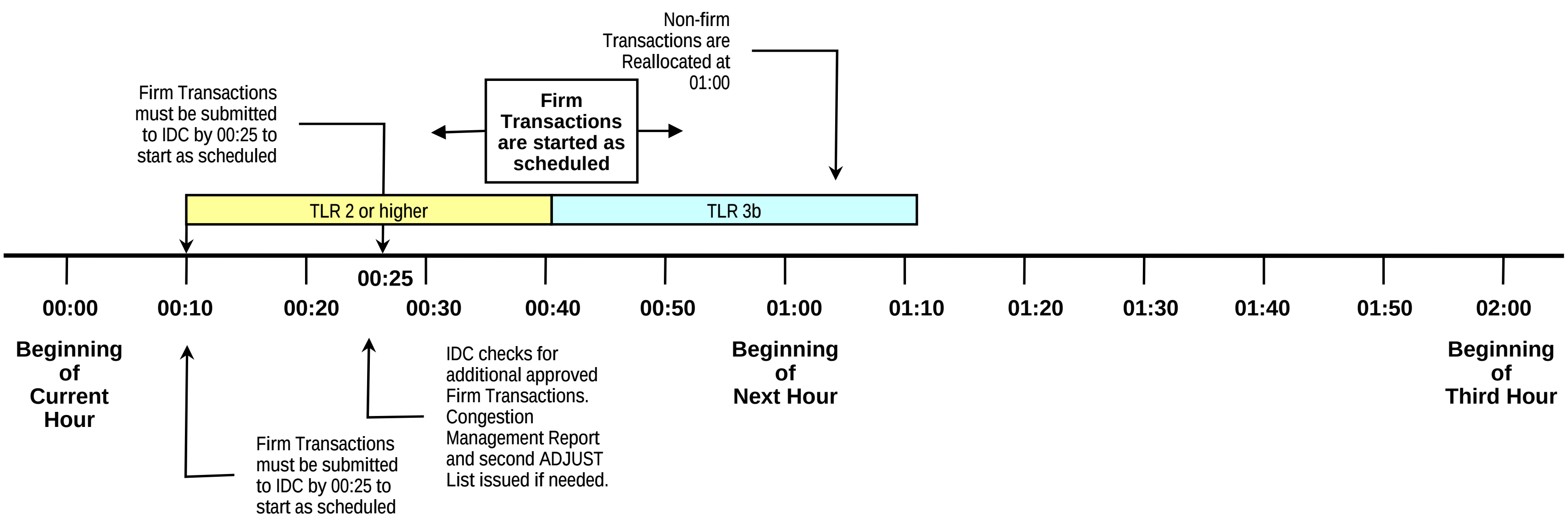
Monitoring ISO Responsibilities

- Monitor and detect congestion [based on look ahead results]
- Ascertain parallel flow impacts on congested flow gate from IDC
- Initiate “request to review” transaction schedules with Responsible Control Area
- Release flow gate transaction scheduling restrictions when congestion no longer expected
- [Subsequently] calculate and communicate congestion charge and allocation to Responsible Control Area

Responsible Control Area Responsibilities

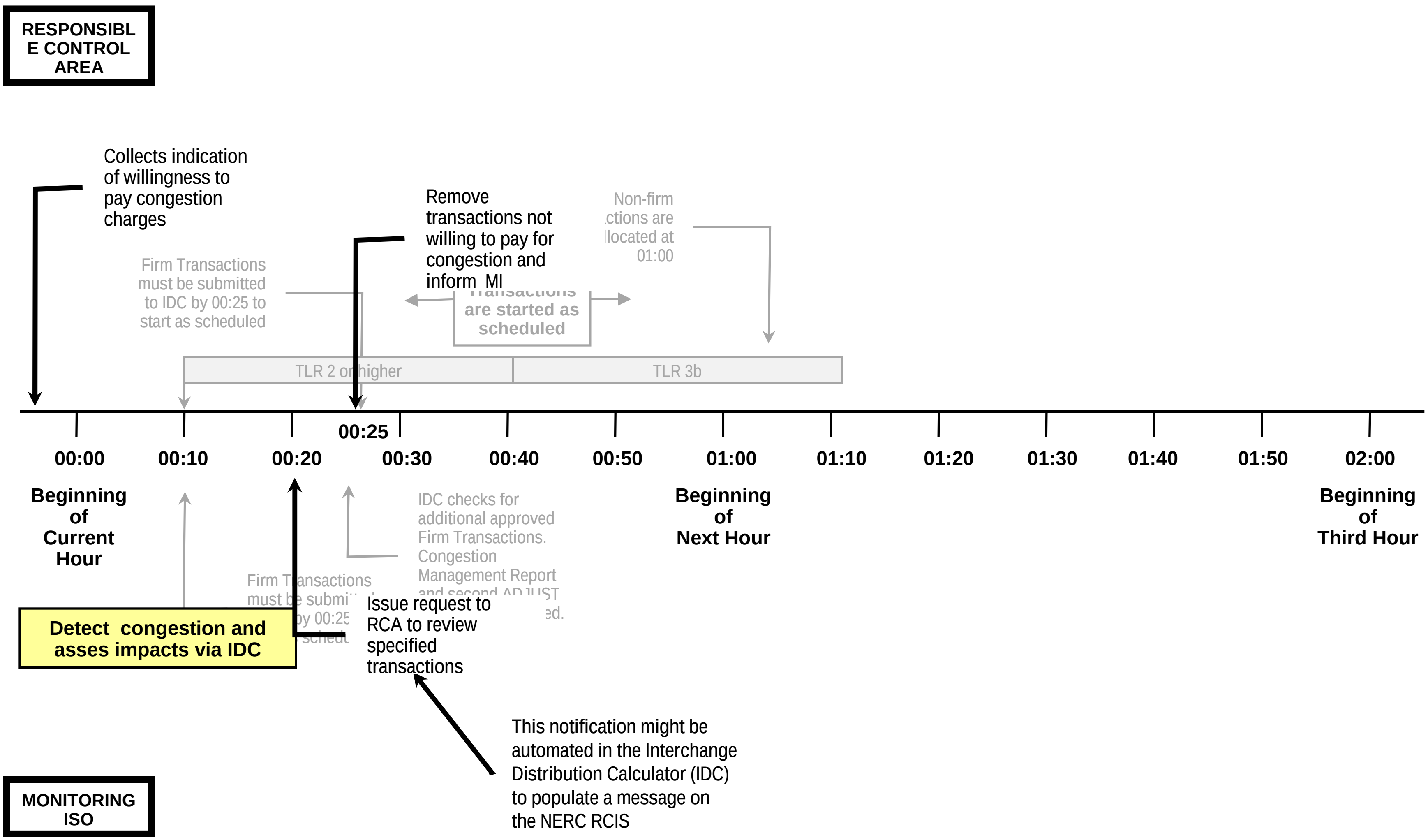
- Collects bidding indicators of “willingness to pay” (off-contract path) congestion from transactions sinking in its market
- schedule or remove relevant transactions following “request to review” from Monitoring ISO
- Process, collect and distribute settlement charges associated with buy-through of congestion

Process Overview – TLR Timeline

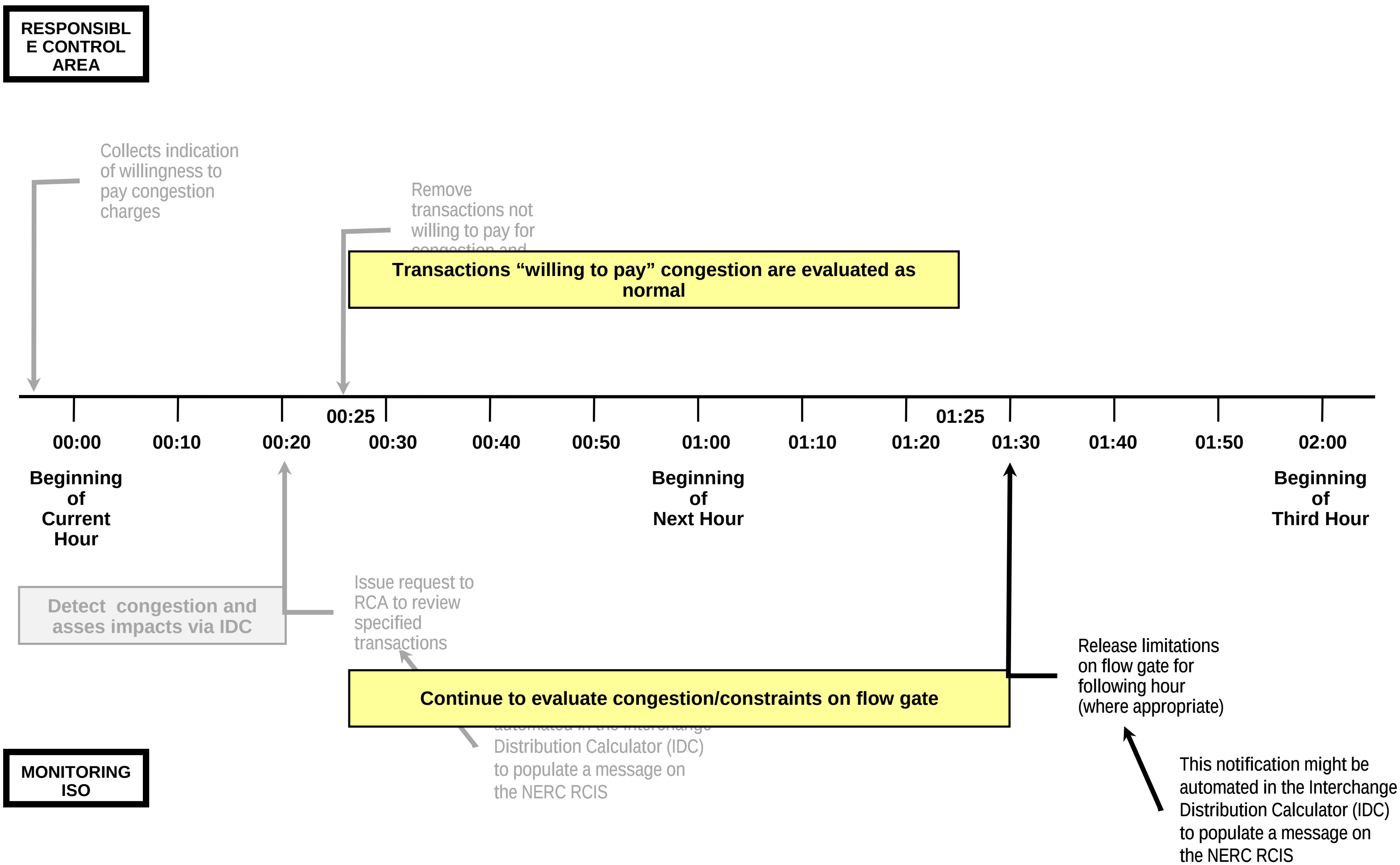


Source: Standard IRO-006-4.1 — Reliability Coordination — Transmission Loading Relief

Process Overview – Transaction Removal



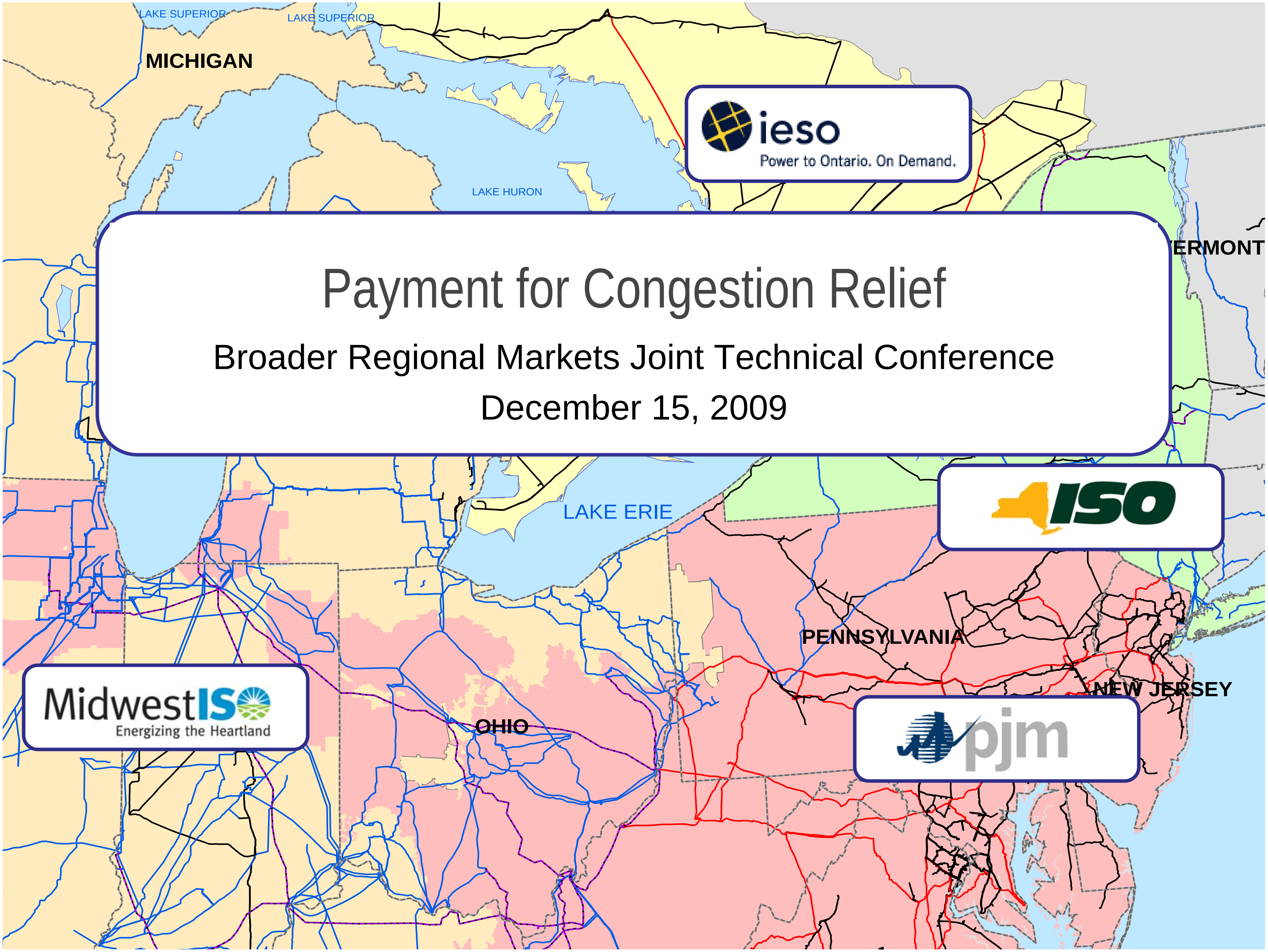
Process Overview – Transaction Re-Instatement



Payment for Congestion Relief

Broader Regional Markets Joint Technical Conference

December 15, 2009



Status

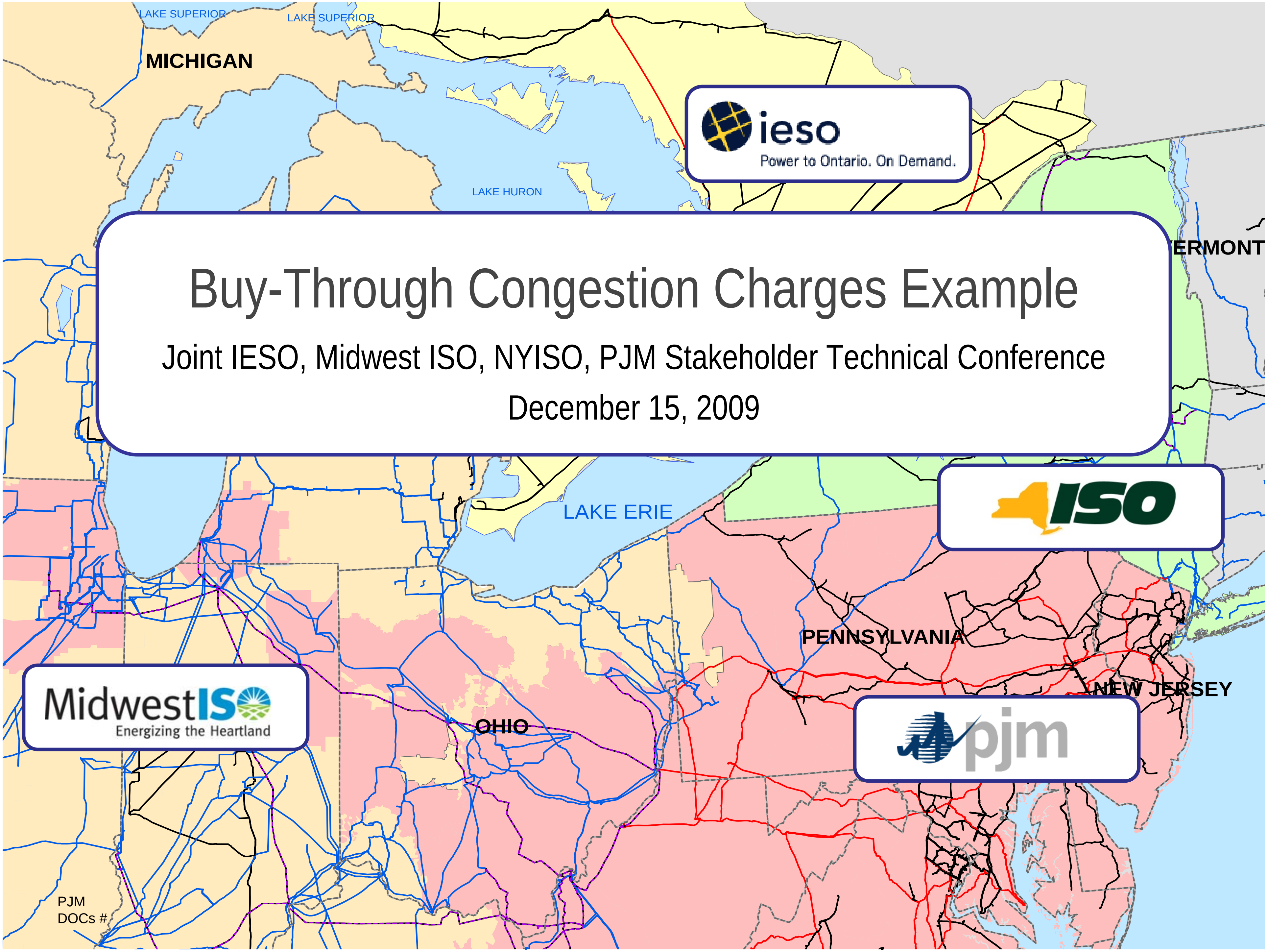
- Indicated by stakeholders as a desirable feature that should be added
- ISO Design Team has considered how this might be accomplished
- Concept identified but not yet fully defined – further consideration of process details needed to confirm practicality and implementability

Process Considerations

- Option should not impose a (residual) cost risk onto region's internal load;
- Alternatively, a trader can explicitly schedule a transaction through the relevant market that is expected to benefit from congestion relief; compensation in this instance is effected via the associated LBMP.

How it might work

- [Off-contract path] forward flows are charged for congestion based on their impact on the congested flow gate
- Counter-flows allow greater volumes of forward flows and hence collection of congestion costs to occur
- Identified counter-flow transactions would be compensated at same MWh rate that forward flows are charged.
- Total compensation paid limited by congestion charges collected at the same time
- Revenue sufficiency (collections versus payments) would be monitored and evaluated to determine whether payment limitation could be adjusted/eliminated



Buy-Through Congestion Charges Example

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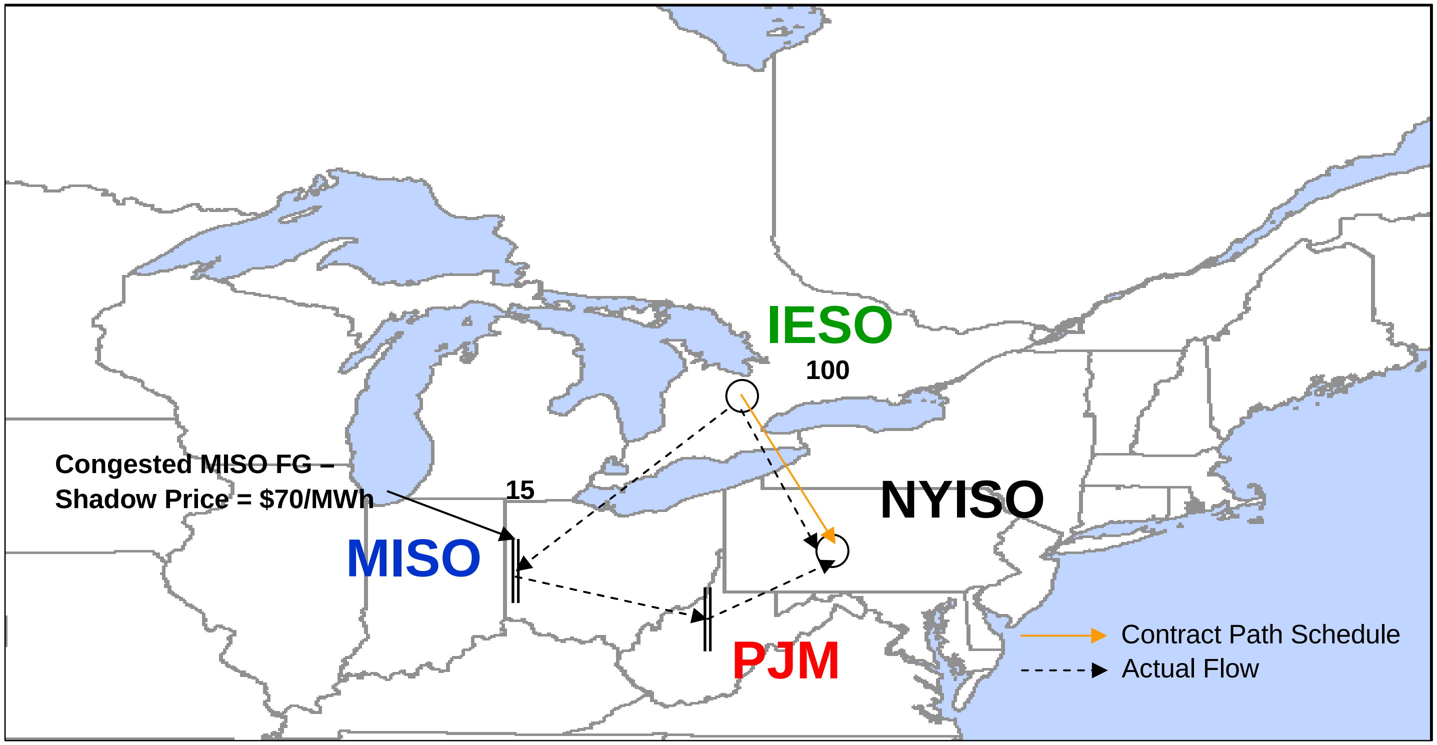
December 15, 2009

Buy-Through of Congestion Charges



Market participant enters into a contract to buy 100 MW of energy from a source within IESO and sell the 100 MW to a sink within NYISO; for one five-minute interval during the hour the contract has a 15% transfer distribution factor on a constrained flow gate within Midwest ISO

Under the Buy -Through of Congestion process, the actual flows from this contract would result in an $87.50* congestion charge from Midwest ISO being billed to the contract holder via their NYISO invoice

Does this result in the contract holder being "over-charged" for congestion?

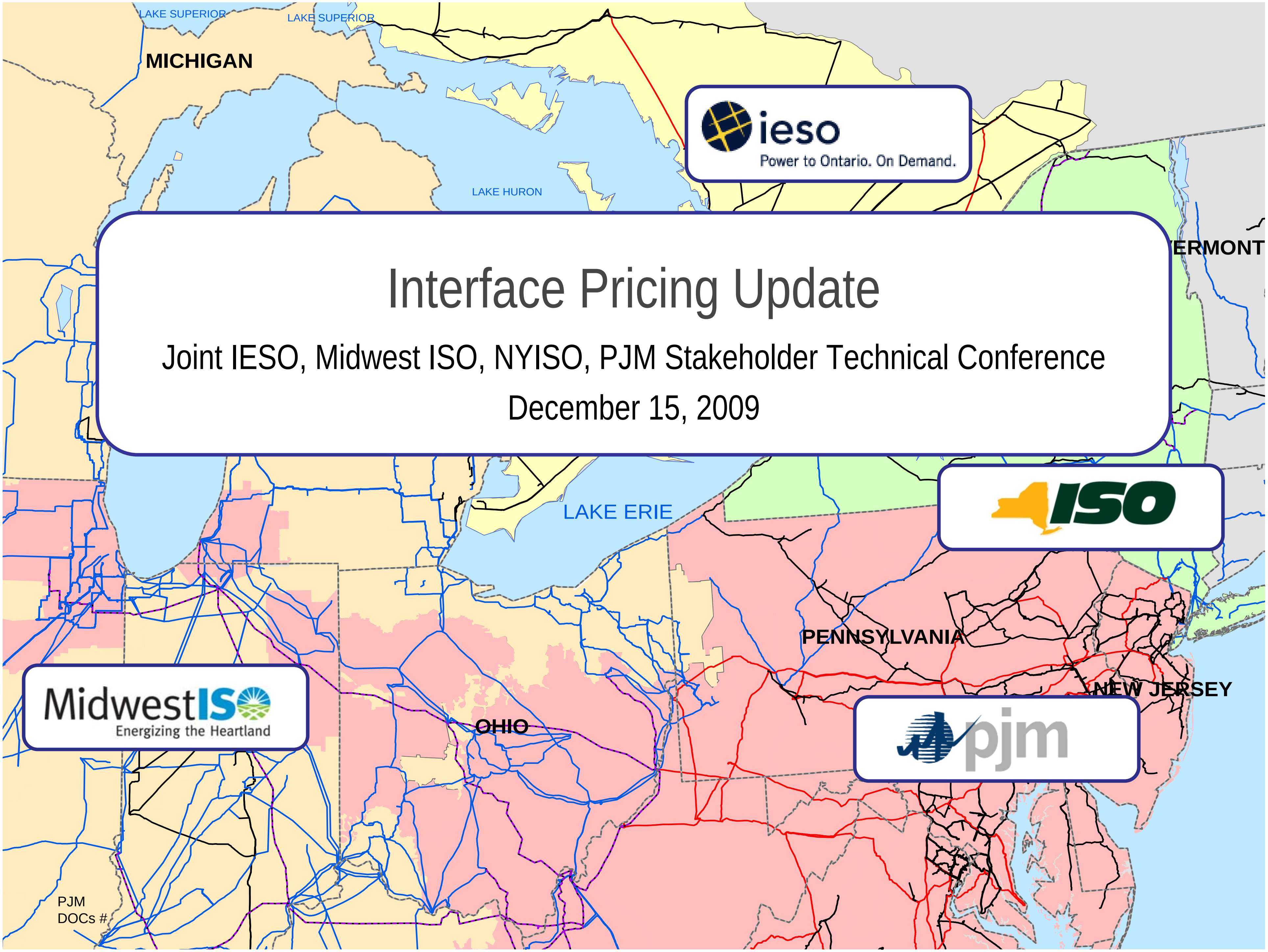
Congestion charge calculation is: $70/MWh * 15% * 100MW * 5/60 h = $87.50

Impact of Parallel Flows on Congestion Charges

- Today, the security constrained dispatch is included in the actual binding necessary to manage the flow gate and thus accounts for the impact of parallel flows.
- For a transaction that is not delivered completely on the contract path, the effect of the actual flows is carried through to the calculation of the shadow price of the constraint
- In the proceeding scenario, if we were to assume a congested flow gate also existed on the NYISO system contract path the flow on the parallel path would result in the contract holder receiving a reduced congestion charge from NYISO for the portion of the flows actually occurring on the NYISO system
- If the parallel path did not exist, all contract path flow would have occurred on the NY flow gate and NY generation would have to be adjusted both upstream and downstream from the constraint to prevent an overload
  - This would generally result in a lower LMP at the source of the contract, and allow the contract holder to pay only a portion of the total congestion caused by the transaction

Impact of Parallel Flows on Congestion Charges

- The parallel flows reduce congestion on the NYISO system but cause increased congestion on a neighboring system – Midwest ISO in this scenario
- The cost of the increased congestion on the Midwest ISO system is not captured in the congestion charged by NYISO
- The implementation of the Buy-Through of Congestion product would create a mechanism for the Balancing Authorities to recover congestion costs associated with those parallel flows
- This process would allow the full cost of congestion to be collected from the cost causer and would not result in a contract holder be "over-charged" for congestion



ieso
Power to Ontario. On Demand.

Interface Pricing Update

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009

ISO

MidwestISO
Energizing the Heartland

pjm

Background

- In 2007, NYISO Experienced a large growth in Lake Erie loop flow, caused in part by a difference in pricing methodologies between NYISO and PJM.
- As part of the July 16, 2009 FERC Order on Lake Erie loop flow, FERC directed the NYISO to develop solutions “including addressing interface pricing”.
- Stakeholder submitted comments questioned the methodologies and the need for consistency.

Review

- Interface pricing and tag based pricing produce similar results when transactions flow on their scheduled paths.
- Circuitous path scheduling may not be appropriate in the absence of the ability to conform actual flows to scheduled flows.
  - Tag-based pricing and path prohibitions may produce similar market responses
- Efficient prices produce desired market behavior and facilitate regional energy interchange.

Recommendation
Without PAR Control in Place

- In recognition of the overall objective of harmonizing the market rules across the region, as well as the current lack of a clear schedule for the implementation and operation of the Ontario – Michigan Phase Angle Regulators to control Lake Erie loop flow, the NYISO will pursue modifications to its interface pricing methodology.
- As such the NYISO will engage its stakeholder community to adjust the interface price methodologies to:
  - Recognize the incremental distribution of power flows around Lake Erie when evaluating and pricing the marginal impacts of transaction and generation schedules;
  - Evaluate the need for and scheduling rules surrounding establishing an additional proxy bus location for the MISO to acknowledge power deliveries from or to the Midwest region;
  - Evaluate the continued applicability of the existing circuitous path prohibitions.

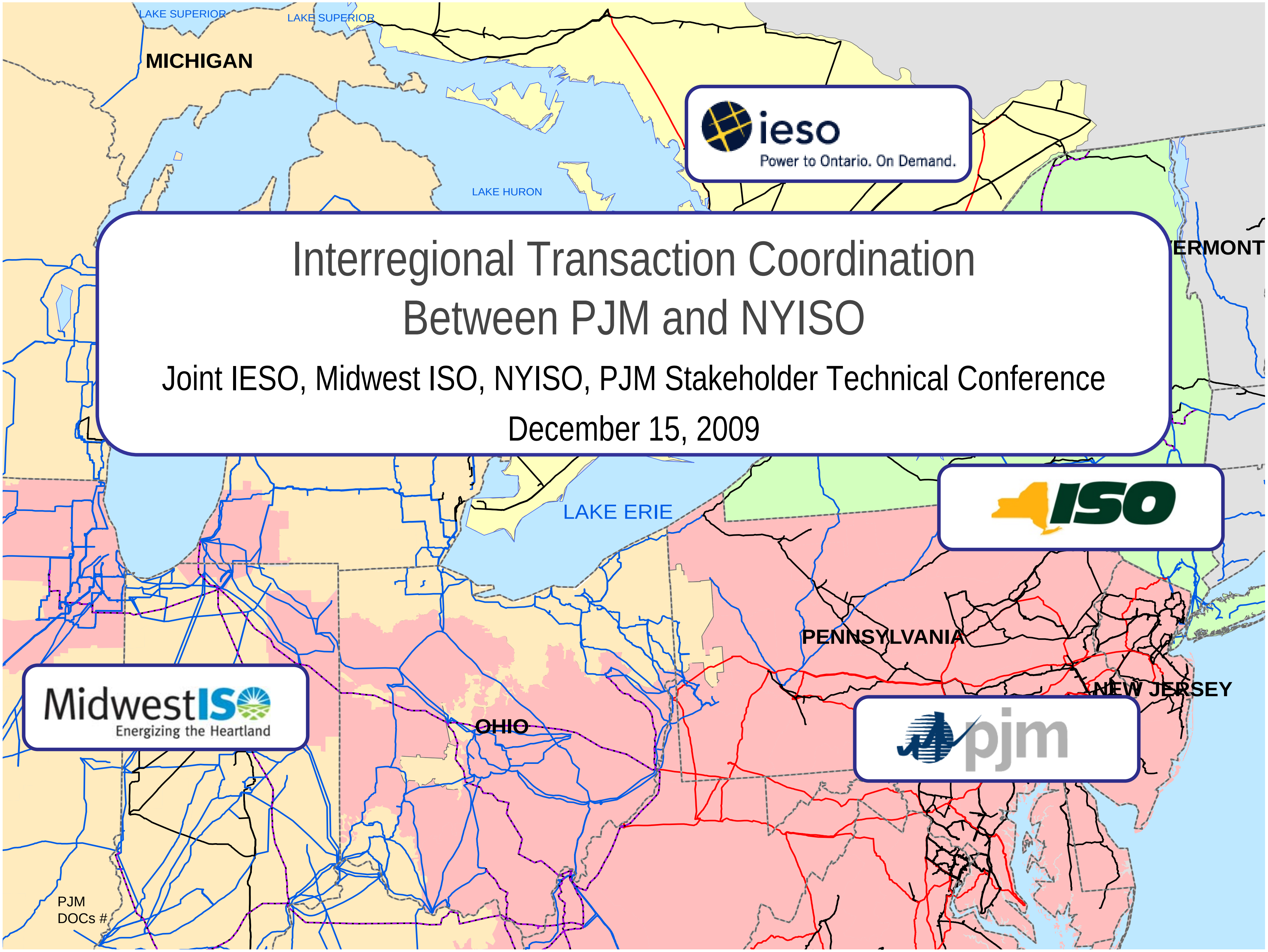
Recommendation
With PAR Control in Place

- To maintain compatible and efficient proxy bus prices when the Ontario-Michigan PARs are installed and operational, the proxy bus pricing methodologies will be considered to:
  - The state of control of the Phase Angle Regulators to manage Lake Erie loop flows.
    - Under Lake Erie loop flow controlled operation, the actual delivery of power and pricing methodologies will reflect contract path, or bid path (consistent with current NYISO and IESO implementations.)
    - Under uncontrolled Lake Erie loop flow operation, the proxy price methodologies will need to reflect the revised power deliveries.
  - Evaluate the revisions necessary to extend tag-based pricing to incorporate contract path deliveries;
  - Evaluate the location(s) established for proxy price determination;
  - Evaluate the ability to predict the controllability of the Phase Angle Regulators to manage Lake Erie loop flows to incorporate the necessary assumptions into the respective Day-Ahead and Hour-Ahead markets.

Interregional Transaction Coordination Between PJM and NYISO

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



PJM-NY
Interregional Transaction Coordination

- Market-Based Scheduling Mechanism allowing for real-time scheduling of transactions between the New York Control Area and the PJM Control Area on a more frequent basis
- The additional scheduling flexibility is intended to allow market participants to minimize buy-through of congestion exposure

PJM-NY
Interregional Transaction Coordination

- Concept
  - Market Participants will provide energy transaction offers in the NYISO and PJM Real-Time Markets, where each markets' real-time scheduling systems would evaluate these transactions on a fifteen minute basis
    - Transmission Reservations continue to be allocated on an hourly basis by PJM
  - The NYISO intends to offer a mechanism for market participants to reduce/reinstate the schedule of their transaction during the dispatch hour
  - The feature will be available for import and export transactions
    - Wheel-through transactions will not be qualified to offer on a 15 minute basis

PJM-NY
Interregional Transaction Coordination

- Phased Approach
  - Phase 1 - Begin with fifteen minute energy transaction scheduling at the controllable line proxy buses between the PJM and NY control areas
  - Phase 2 – Continue to expand the fifteen minute energy scheduling process to the 'AC' interface between the PJM and NY control areas

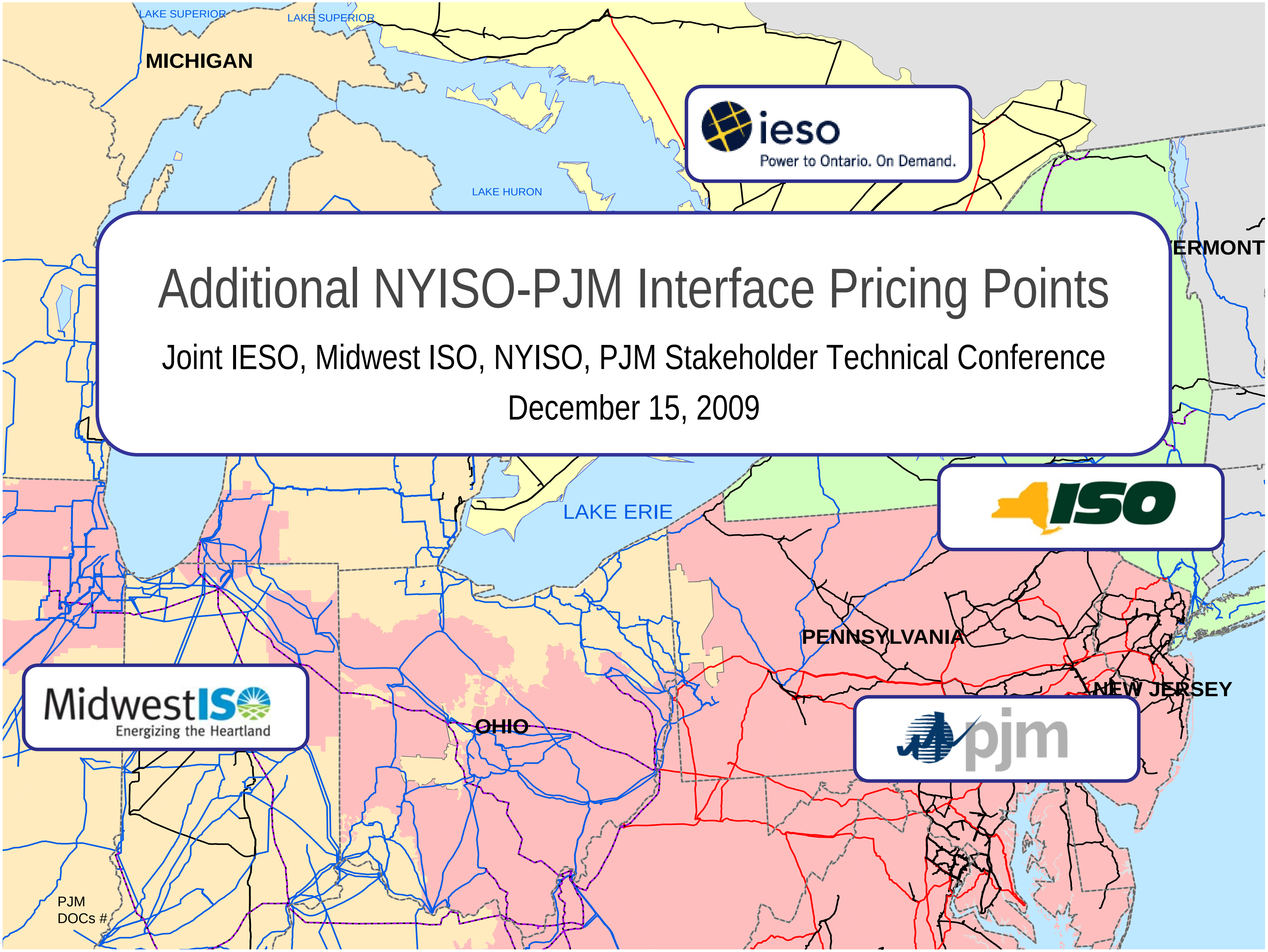
PJM-NY
Interregional Transaction Coordination

- PJM and NY to continue discussions on opportunities to achieve more efficient scheduling outcomes through increased coordination of, and greater frequency of, scheduling decisions
- 2010 – Work with NY and PJM stakeholders on furthering the concept

Additional NYISO-PJM Interface Pricing Points

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



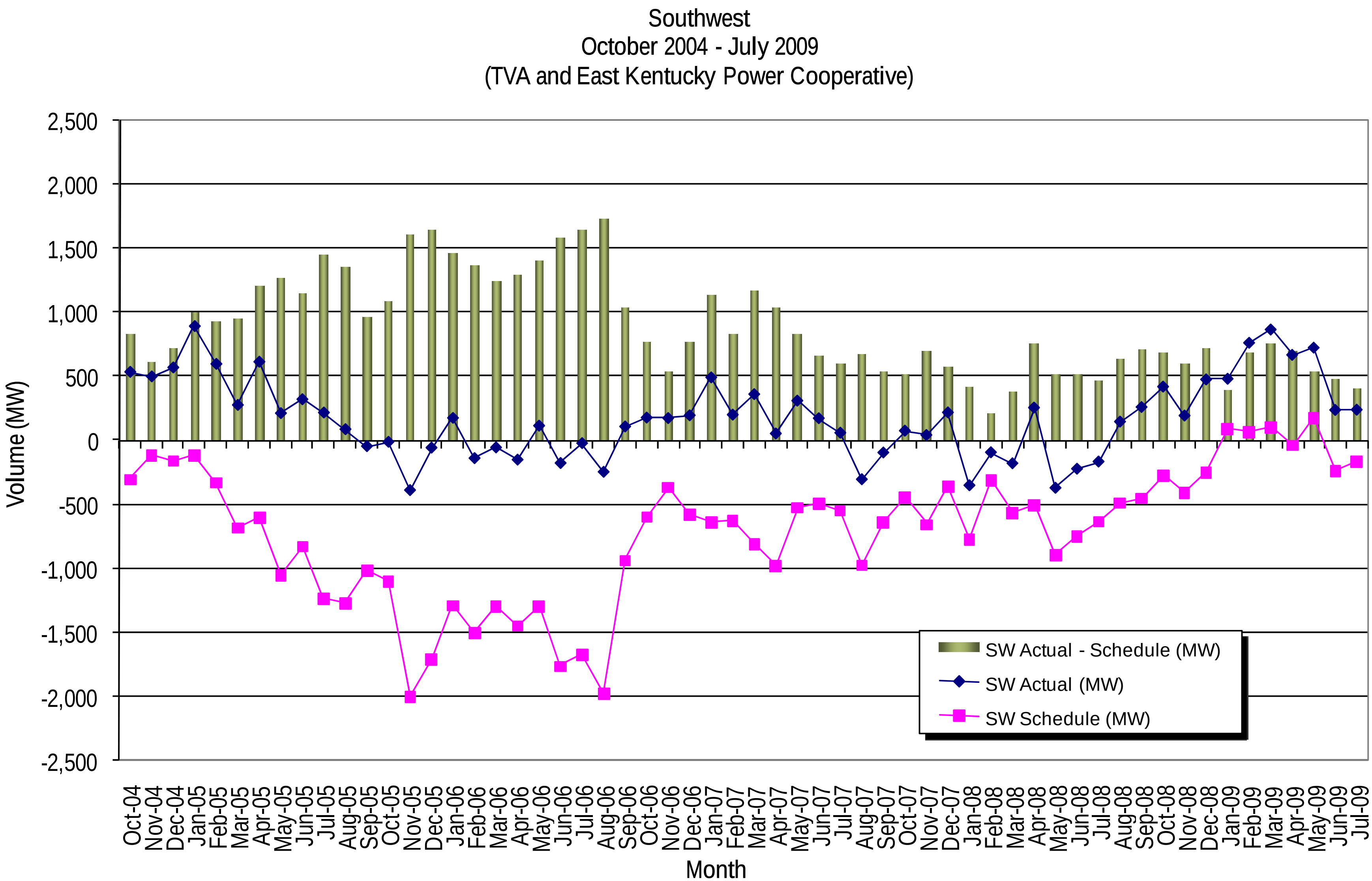
Background

- Market participants have expressed a desire for NYISO and PJM to establish additional pricing points on the interface between NYISO and PJM
- At the present time there are three interface pricing points between the NYISO and PJM
  - AC interconnected facilities between NYISO and PJM
  - Neptune DC interconnection between NJ and Long Island, NY
  - Linden Variable Frequency Transformer (VFT) interconnection between NJ and NYC

Observations and Concerns

- Additional pricing points along a free-flowing AC interface have historically provided market participants with the ability to game that interface through transaction scheduling activities
- This behavior is difficult for transmission providers to easily identify and mitigate during real-time operations
- NYISO and PJM staffs believe the creation of additional pricing points along the free-flowing AC interface would create opportunities for gaming the interface between NYISO and PJM
  - Potential for increasing loop flows around Lake Erie is a major concern

PJM Southwest Interface



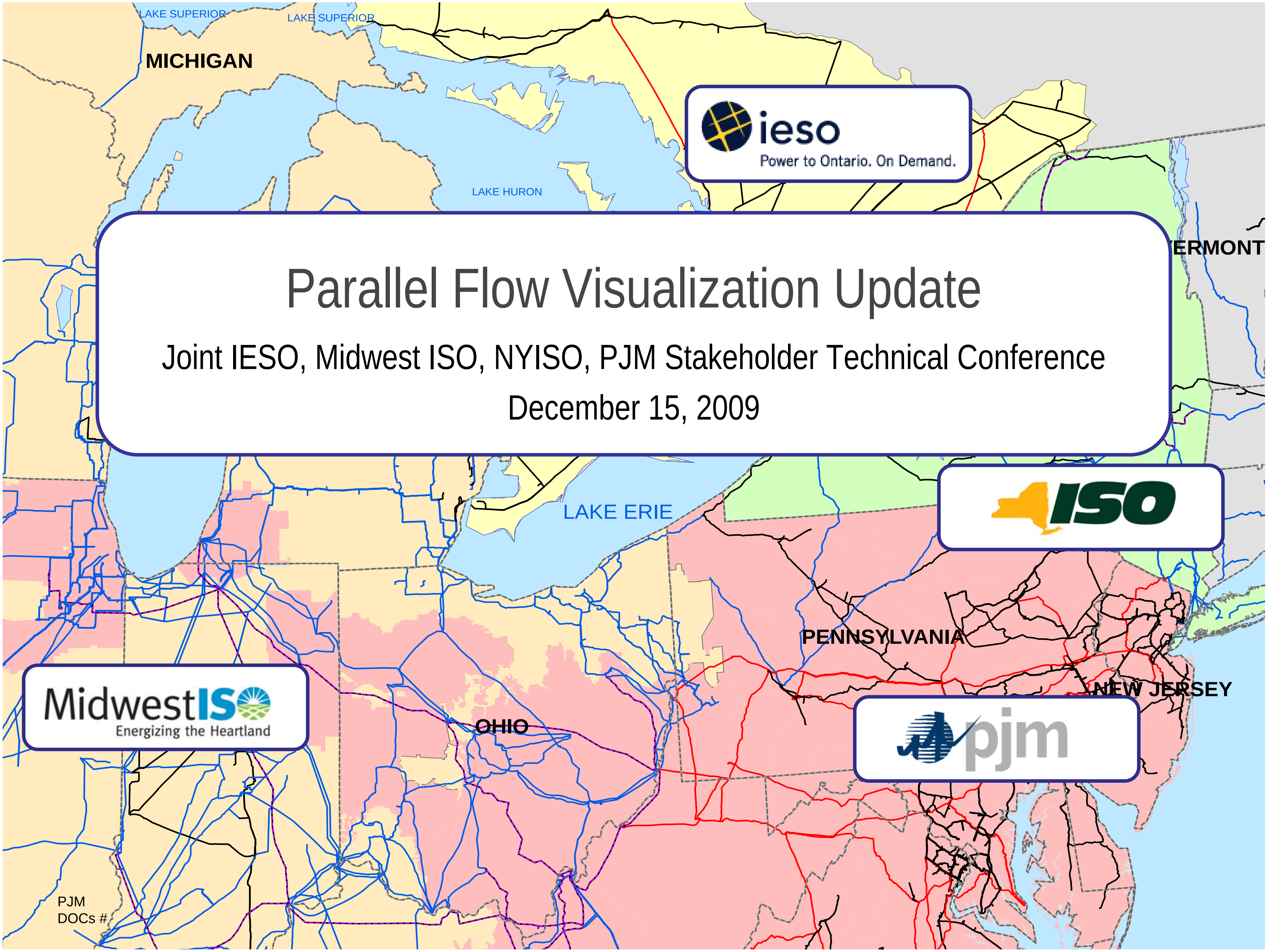
Potential New Interfaces

- The deployment of new technologies which provide the ability to completely control scheduled flows may allow for the establishment for additional pricing interfaces
  - Variable Frequency Transformers for example
  - Control capability must exist to prevent the introduction of additional loop flows
- The potential for establishing new pricing points will be evaluated by the staffs of NYISO and PJM going forward

Parallel Flow Visualization Update

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



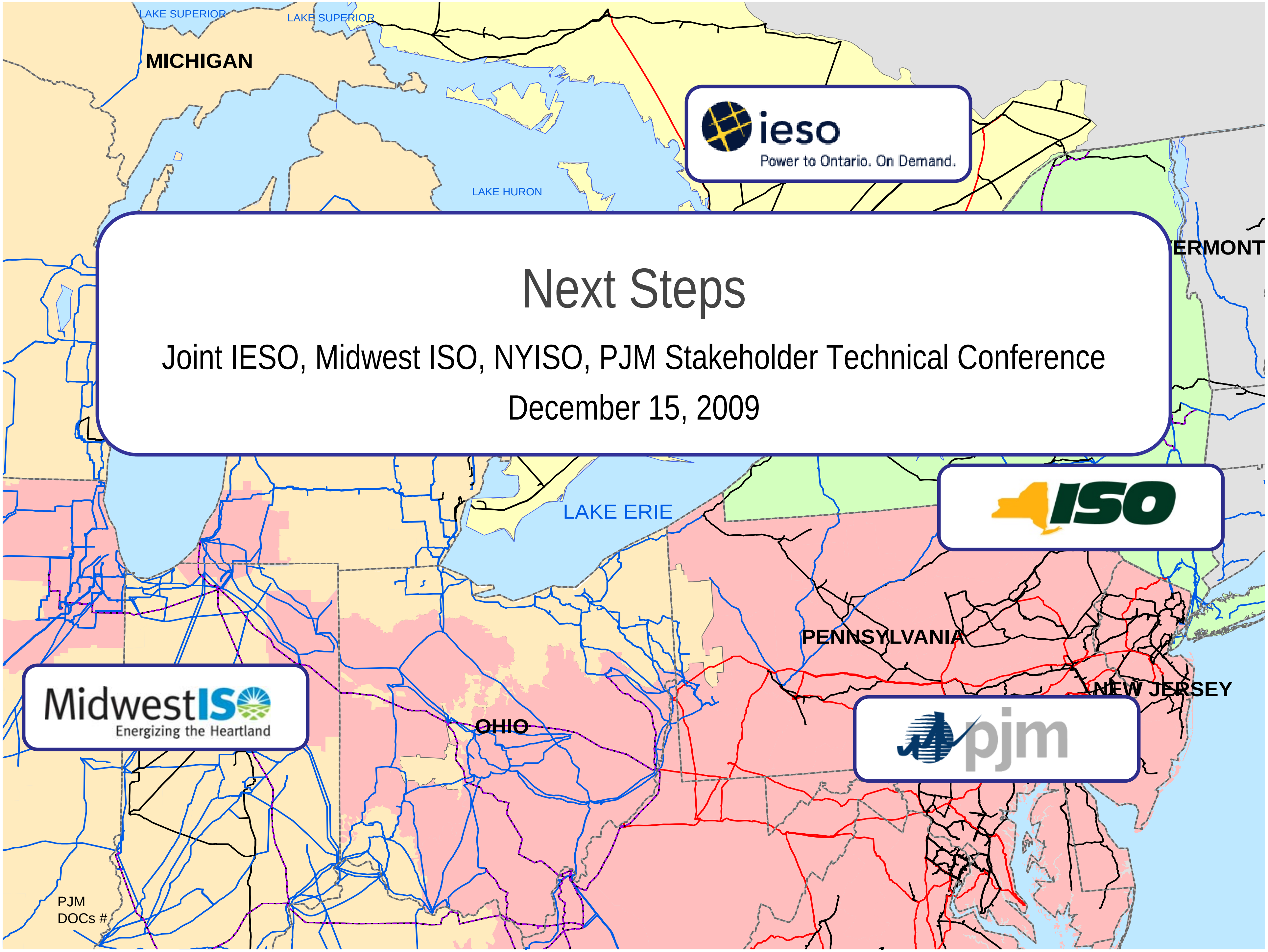
NERC Parallel Flow Visualization Project

- The NERC Parallel Flow Visualization (PFV) Project detail was presented at the October 29 joint stake holder conference.
- The project will enable a RC to distinguish the source of flow between (A) each separate region's impacts associated with generation-to-load dispatch and (B) individual transaction impacts
- The NERC ORS at their November 2009 meeting approved moving forward with the project. This included selection of the vendor and the detailed timeline.
- Beginning November 1, 2010 and after a 12 to 18 month trial period following NERC ORS approval the project would be placed in production.
- We have agreed to assess the progress of the project in June of 2010. If the solution is determined to be abandoned, unsupportable, or unachievable, the ISOs will pursue alternative solutions to the visibility initiative in an effort to maintain the currently proposed solutions implementation timelines.

Next Steps

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009



Potential Implementation Timeline*

• Parallel Flow Visualization	
– Software Ready	4Q – 2010
– Parallel Operations	4Q – 2011
• Regional PAR Coordination Operating Guide	
– Initiate Regional Study	2Q – 2010
• Interface Pricing Revisions	
– NYISO Revisions - Design	2Q – 2010
• Buy-Through of Congestion	
– Design Development	4Q – 2010
– Implementation	3Q – 2011
• Congestion Management	
– PJM-NYISO Implementation	3Q – 2011
– Extend to Additional Regions	2012
• Interregional Transaction Coordination	
– Energy Scheduling with NY/HQ	1Q – 2011
– Energy Scheduling with NY/PJ	4Q – 2011
– Extend to Additional Regions	2012

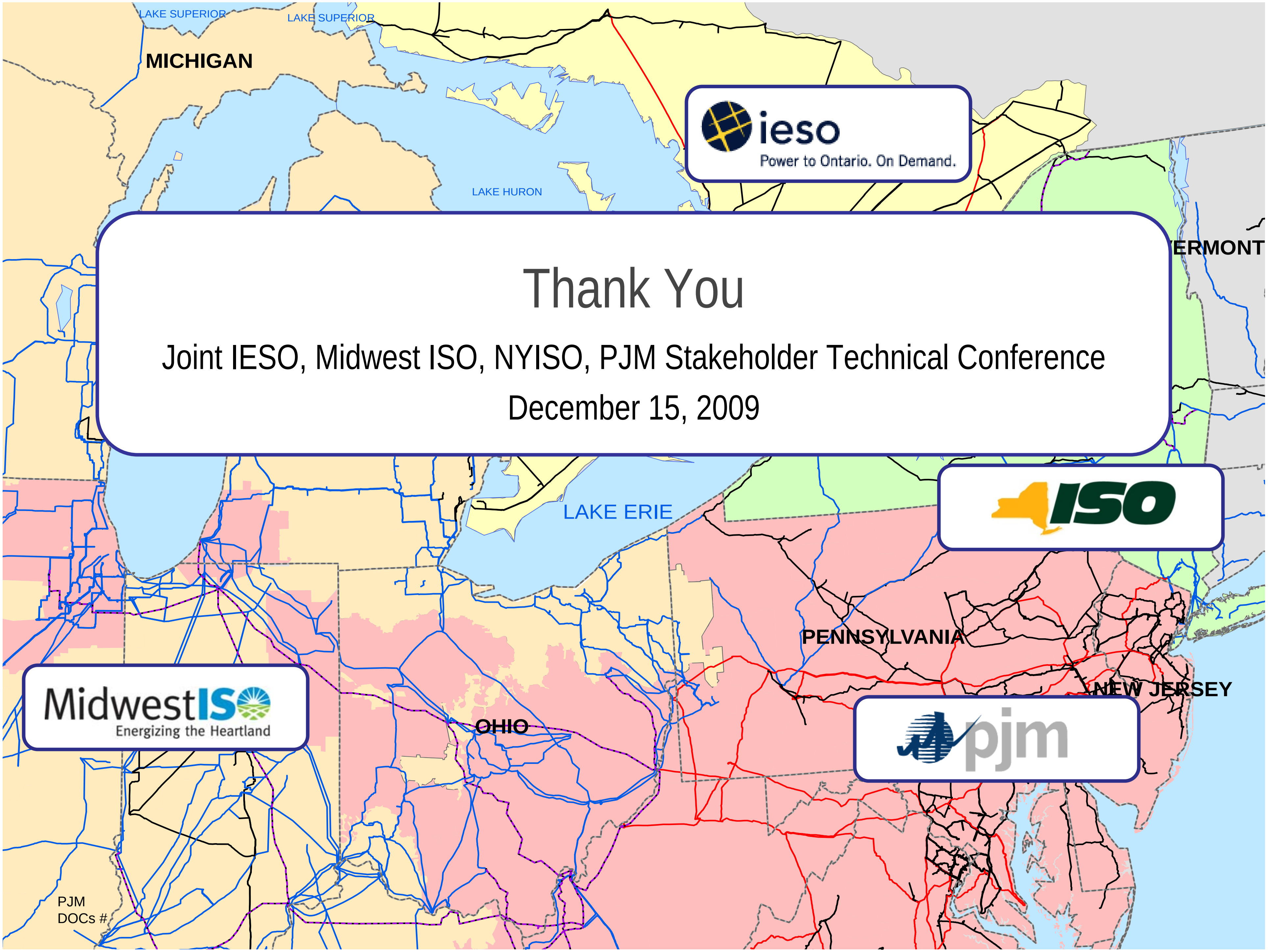
*Prospective timeline pending design development and approval from Market Participants, neighboring Control Areas and the Commission.

FERC Report

- File report with FERC detailing proposed solutions on January 12, 2010.
- Submission will include:
  - Broader Regional Markets Solutions to Loop Flows – White Paper
  - Potential Implementation Timeline
  - Ongoing Efforts

Ongoing Efforts

- Continued design and detail development of recommendations
  - Additional feedback and discussion
  - Detailed design, Joint Operating Agreements and tariff development beginning in 2010.
- Implementation of Parallel Flow Data Reporting
- Periodic Joint Stakeholder Briefings
  - Anticipating quarterly meetings.
- Complete Benefits Assessment



Thank You

Joint IESO, Midwest ISO, NYISO, PJM Stakeholder Technical Conference

December 15, 2009

Attachment C

Broader Regional Markets,
Long-Term Solutions to Lake Erie Loop Flow
Slide Presentation from the October 29, 2009
Technical Conference Held in Albany, New York

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Broader Regional Markets

Solutions to Loop Flow

Technical Conference

Joint Meeting of NYISO-PJM-MISO-IESO Stakeholders

Desmond Hotel and Conference Center

Albany, NY

October 29, 2009

Agenda

- **Welcome** -- *Stephen G. Whitley - NYISO*
- **Technical Conference** -- *Rana Mukerji - NYISO*
  - *Introductions*
  - *Background*
- **Proposed Solutions to Loop Flow** -- *Robert Pike - NYISO*
  - *Physical Solutions -- Peter Sergejewich - IESO*
  - *Parallel Flow Visualization -- Tom Mallinger - MISO*
  - *Market Solutions*
    - Buy-Through of Congestion -- *Robert Pike - NYISO*
    - Congestion Management -- *Stan Williams - PJM*
    - Interregional Transaction Coordination -- *Robert Pike - NYISO*
- **Next Steps** -- *Rana Mukerji - NYISO*
  - *Potential Implementation Timeline*
  - *Feedback*
  - *Ongoing Efforts*

Welcome

- **Coming together is a start…**
- **Staying together is progress…**
- **Working together is success!**

Technical Conference

- Introductions
- Conference Expectations
- Background

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FERC Order

July 16, 2009 Lake Erie Loop Flow Report/Order

- Finds no evidence of market manipulation by market participants scheduling external transactions around Lake Erie
- Determines that there were no tariff violations by the NYISO or by market participants
- Orders the NYISO to "expeditiously develop long-term comprehensive solutions to the loop flow problem with its neighboring RTOs, including addressing interface pricing and congestion management."
  - *NYISO must submit a report to FERC detailing its proposed solution, including necessary Tariff revisions, by mid-January 2010*

Proposed Solutions

Robert Pike - NYISO

Concept Development

- Stakeholder meetings to review background issues and solutions to loop flow concepts.
  - *Individual ISO briefings to stakeholders on concepts*
- Joint ISO Meetings
  - *Senior level scope reviews and updates*
  - *Weekly conference calls and additional in-person meetings to develop concepts of buy-through of congestion and congestion management as well as potential timeline.*
  - *Developing whitepaper that describes the proposed solutions in greater detail*
- Any solutions will require tariff development and stakeholder support.

Current Market Outcomes

- Day-Ahead Modeling:
  - *All ISO's incorporate a prediction / forecast of Lake Erie loop flows into their respective Day-Ahead evaluations.*
    - NYISO updates weekly based upon the hourly loop flows experienced in real-time over the past 30 days.
    - PJM updates annually based upon hourly loop flows experienced in real-time over the past year.
    - IESO updates daily based upon previous days experienced loop flows resulting from firm transaction schedules.
    - MISO updates quarterly, with daily incremental revisions, based upon system projected conditions.
- Real-Time Operation:
  - *All ISO's incorporate real-time actual loop flows into the market solutions.*
- Transmission Loading Relief (TLR) events initiated to address reliability constraints on flow gates impacted by Lake Erie loop flows.

Broader Regional Markets

- Proposed Solutions to Loop Flows
  - *Physical Solution*
    - Installation and operation of the Michigan/Ontario PARs to better conform actual power flows to scheduled power flows
  - *Parallel Flow Visualization*
  - *Market Solutions*
    - Buy-Through of Congestion
    - Congestion Management (Market-to-Market Coordination)
    - Interregional Transaction Coordination

Solution Objectives

- Reduce need for, frequency of, and magnitude of Transmission Loading Relief (TLR) events to address loop flow.
  - *Buy-Through of Congestion provides an alternative to market and operational interruptions caused by TLR events; establishes an economic based alternative to imposed curtailments.*
- Align constraint management cost recovery with sources of flow
  - *Parallel Flow Visualization and Buy-Through of Congestion facilitate identification of sources of loop flow and provide a mechanism to recover congestion management costs incurred to support loop flows.*
- Reduce constraint management costs for consumers across region.
  - *Congestion Management achieves a more cost effective utilization of the region's collective assets to address constraints across multiple systems.*
- Improve regional price consistency and transmission utilization
  - *Congestion Management expands asset pool to address regional constraints.*
  - *Interregional Transaction Coordination provides for the more frequent adjustment of interchange schedules in response to changing market conditions; expands pool of flexible assets to balance intermittent power resources output.*

Physical Solution

Peter Sergejewich - IESO

ieso Power to Ontario. On Demand.

Physical Solutions to Loop Flows

- Some control of loop flow can be achieved through the use of physical devices such as phase shifting transformers, also know as phase angle regulators or PARs.
- In addition to PARs, variable frequency transformers, series capacitors, and other such devices have the ability to alter flows and should be coordinated and included in solutions to loop flows.
- Of particular note in respect to controlling loop flows around Lake Erie are the Ontario-Michigan PARs which are soon to be in-service. Once in-service, Ontario will have the ability to control the flows across each of its interconnection interfaces to some extent, and in particular the circulation flow across the top of Lake Erie.
- The intent is to operate the Michigan-Ontario PARs so as to better match actual flows with the scheduled flows across the interconnection.

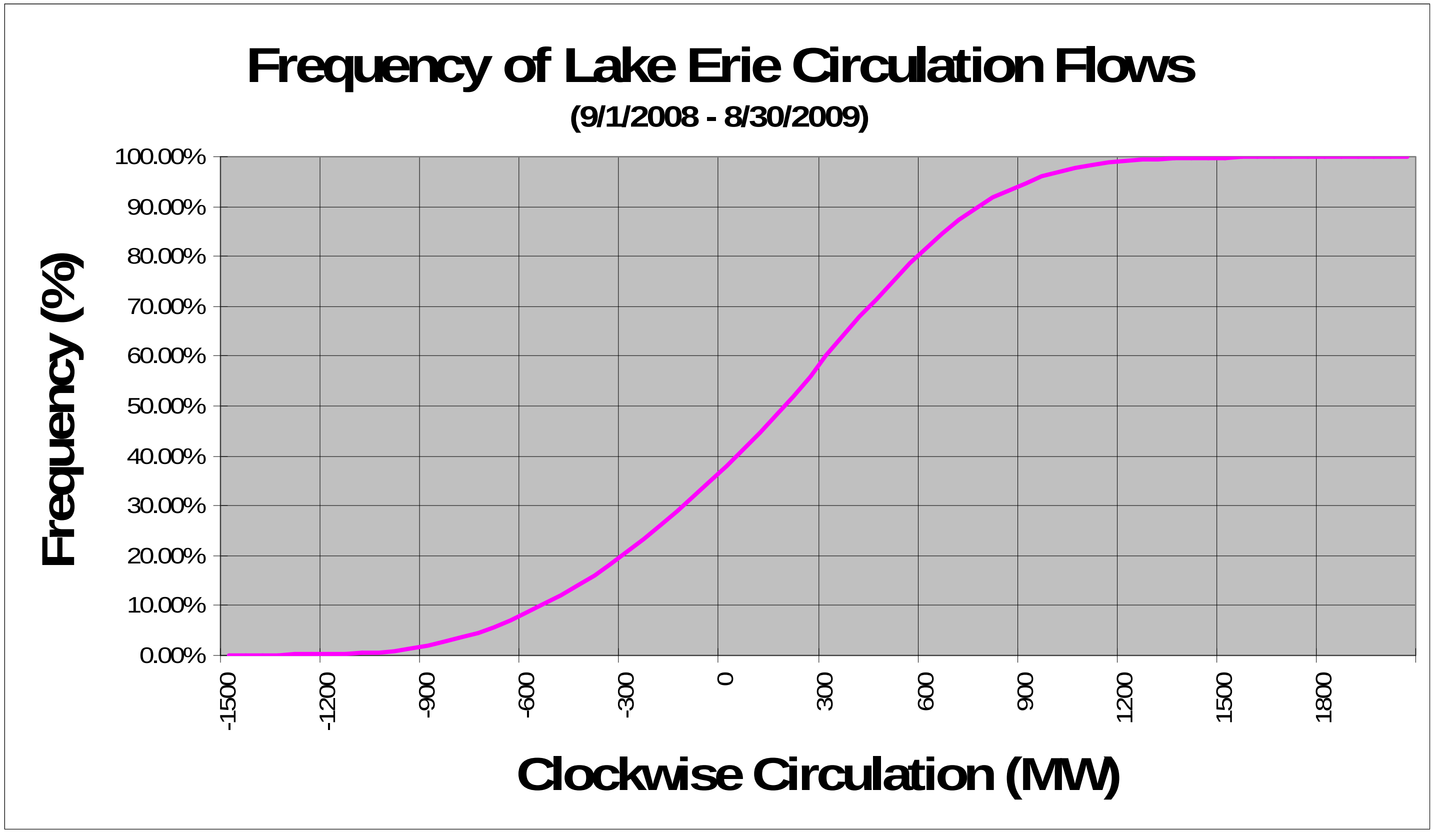
Status of Michigan-Ontario PARs

- Initial installation completed in 1999
- Ongoing operation delayed due to equipment failures & difficulties in getting operating agreements in place
- Failed equipment replaced and additional further protection upgrades scheduled to be in place by the end of Q1 2010

ieso Power to Ontario. On Demand.

Capability of Michigan-Ontario PARs

- Expect to be able to control up to 600 MW of loop flow in either direction



Coordinated Operation of All Devices

- All physical controls will play a complementary role in any comprehensive loop flow solution
- Since uncoordinated operation of physical devices could increase circulation flows, it is important that the operation of such devices by the four markets around Lake Erie be coordinated to avoid detrimental impacts.

Parallel Flow Visualization

Tom Mallinger - MISO

Parallel Flow Visualization/Mitigation Proposal

Joint Meeting of NYISO-IESO-MISO-PJM Stakeholder
October 29, 2009

Midwest ISO Energizing the Heartland

pjm

SPP Southwest Power Pool

History of TLR in Eastern Interconnection (EI)

- Primary congestion management procedure used during the past 10 years. Only minor modifications have been made during this time period.
- Where TLR is not the primary congestion management mechanism, it has been used as a reliability backstop when significant, externally induced parallel flows make local procedures insufficient to control facility loading.
- Historically, Reliability Coordinators (RCs) have relied on tag curtailments to curtail non-firm usage and a combination of tags and NNL relief obligations to curtail firm usage (share-the-pain approach).

Recent Enhancements to the TLR Procedure

- With the expansion of the PJM market and the start of the Midwest ISO and SPP markets, the TLR procedure has been enhanced to include market flows on the systems of these entities in place of tags.
- Midwest ISO and PJM have implemented a M2M congestion management process where they use the most cost effective generation in the two markets to meet their combined relief obligations during TLR.

RCs Rely on IDC for Parallel Flow Information

- RCs monitor real-time flows using RTCA and SCADA. This process is effective monitoring total flow but does not identify the source and magnitude of parallel flows.
- Transaction impacts for current hour and next hour are available in the IDC.
- Likewise, Midwest ISO, PJM and SPP generator-to-load (GTL) impacts for current hour and next hour are available in the IDC.
- An RC should know its own GTL impacts. However, there is no real-time information in the IDC on parallel flows caused by the GTL impacts from outside the RC area.

Instances When Parallel Flows in the EI Caused Reliability Concerns

Lake Erie Circulation Flow

- The MISO-PJM Loop Flow Study Phase I report documented instances when high clockwise and counter-clockwise loop flows occurred around Lake Erie:
  - Two dates involved high clockwise flows (on Feb 17, 2005 and April 17, 2005).
  - Two dates involved high counterclockwise flows around Lake Erie (on March 1, 2005 and June 23, 2005).
- The Loop Flow Study Phase I report identified the magnitude of the circulation flows, their direction and the time of the day when they occurred.
- Due to the difficulty of obtaining historical tag impacts and GTL impacts, the Loop Flow Study Phase I report recommended creating an Energy Schedule Tag Archive that contains tag impacts, market flow impacts and GTL impacts for all flowgates contained in the IDC.

Instances When Parallel Flows in the EI Caused Reliability Concerns

Lake Erie Circulation Flow

High counter-clockwise Lake Erie circulation flows occurred on June 11-13, 2007. IESO implemented TLR 3a on FG 7102 (QFW) that resulted in the following PJM relief obligations:

June 11, 2007 TLR 3a	13:00-14:00 CST	29.8 MW
	15:00-16:00 CST	373 MW
June 12, 2007 TLR 3a	10:00-11:00 CST	235 MW
	11:00-12:00 CST	243 MW
	12:00-13:00 CST	76.8 MW
	13:00-14:00 CST	177.7 MW
	14:00-15:00 CST	180.9 MW
	15:00-16:00 CST	299 MW
June 13, 2007 TLR 3a	14:00-15:00 CST	9.9 MW
	15:00-16:00 CST	152.5 MW
	16:00-17:00 CST	25.8 MW

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Instances When Parallel Flows in the EI Caused Reliability Concerns

Lake Erie Circulation Flow

- IESO reported that on June 12, 2007, a combination of transmission and generation contingencies plus high Lake Erie circulation contributed to IESO initiating its voltage reduction program.
- January-December, 2008-IESO call TLR on Lake Erie flowgates 163 times. This is usually an indication that there are high circulation flows around Lake Erie.

Major Issues Being Addressed by Proposal

- Replacing the current native and network load (NNL) calculation made in the IDC with the reporting of near real-time flows addresses three major issues:
  - NNL calculation made in IDC is used when TLR 5 is called (firm curtailments). Use of static data in NNL calculation produces questionable results, delays in calling TLR 5 and allows no after-the-fact reviews.
  - RCs in EI lack visualization as to the source and magnitude of parallel flows when they experience congestion.
  - IDC NNL calculation currently assumes all GTL impacts are firm and can only be curtailed on a pro-rata basis during TLR 5.

Use of Static Data in NNL Calculation

- NNL calculation in the IDC relies heavily on operating information submitted to the SDX to model system conditions. There is no NERC requirement that operating data be submitted to the SDX.
- Default assumptions are used where operating information is missing (i.e. generator outages, load and net scheduled interchange).
- There must be a total of 20 MW or more generation at a bus in order to have NNL impacts determined.
- Because NNL calculation is made on an on-demand basis, RCs must adjust the static data to improve the NNL relief obligation. This can delay calling TLR 5 anywhere from 30 to 45 minutes.
- Because NNL calculation is made on an on-demand basis, there is no real-time view of GTL parallel flows (except during TLR 5). There is no historical archive of impacts that could be reviewed on an after-the-fact basis.

RCs Lack Parallel Flow Visualization

- Because NNL calculation is made on-demand and uses static operating information, it is not a suitable source for real-time impact of parallel flows.
- Midwest ISO and PJM issued a Loop Flow Study Phase I report in May 2007 that focused on Lake Erie circulation flow and PJM Southeast versus Southwest Interface flows (http://www.jointandcommon.com/working-groups/joint-and-common/joint-and-common-wg.html).
- Midwest ISO and PJM issued a Loop Flow Study Phase II report in November 2008 that focused on the source and magnitude of parallel flows on 35 flowgates that experienced significant congestion in 2007 (http://www.jointandcommon.com/working-groups/joint-and-common/joint-and-common-wg.html).
- Both loop flow studies took longer to produce and required extensive simulation due to limited historical information on loop flows. One of the Loop Flow Study Phase I recommendations is to create an archive of tag impacts, GTL impacts and market flow impacts that can be used to make after-the-fact reviews.

Generators Using Non-Firm Transmission Service

- For TSPs that are subject to an OATT, designated resources are considered firm use of the transmission system. Non-designated resources are considered non-firm use of the transmission system.
- The IDC is unable to assign relief obligations to non-firm GTL impacts during TLR. If a non-designated resource is below the 20 MW threshold, transmission usage is treated firmer than firm.
- Tagging these non-firm uses not effective since the IDC lacks the granularity to determine tag impacts of intra-BAA transactions.
- Instances where non-firm transmission service is used to serve load within the BAA:
  - Non-designated resources that are being used to serve load inside the BAA have the highest priority of non-firm service (Priority 6-NN).
  - Renewable resources that have elected to use non-firm transmission service to deliver to load inside the BAA.
  - Qualifying facilities that are delivering to load within the BAA.

Parallel Flow Visualization/Mitigation Proposal

- RCs would report their GTL impacts to the IDC on a real-time basis or make arrangements to have someone report on their behalf.
- The IDC would indicate the source of all flows on a flowgate and the priority of these flows (tag impacts, GTL impacts and market flow impacts).
- An RC experiencing congestion would have visualization of the magnitude and source of all flows affecting their flowgate using information from the IDC.
- An RC experiencing congestion would request an amount of flow reduction that would be processed by the IDC. A relief obligation would be issued to all parties contributing to the loading.
- NAESB will establish methodology for assigning the GTL flows into the appropriate buckets.

NERC Involvement in Parallel Flow Proposal

- A comprehensive parallel flow motion was approved at the May 6, 2009 ORS meeting (see attached motion). It provided direction to the IDCWG to develop a final set of requirements, to seek revised vendor estimates and to prepare a recommendation that will be reviewed at the Nov ORS meeting.
- The ORS addressed a number of issues on the approach to be taken:
  - A single vendor will make the GTL calculation for all RCs in the EI.
  - The three RTOs that currently report their market flows to the IDC will replace their own calculation with the vendor calculation.
  - A staged implementation of the new software where it would run in parallel with the existing IDC for some period of time. There will be a set of reliability metrics that demonstrate an improvement over the NNL calculation before changing to the new software.

NERC Involvement in Parallel Flow Proposal

- The IDCWG has held a number of meetings on the parallel flow visualization process. They have identified data requirements and are reviewing IDC COs.
- The IDCWG presented the data requirement at the Sept 23, 2009 ORS meeting.
- The IDCWG will recommend a parallel flow process and a vendor at the Nov 2009 ORS meeting.
- The 2010 NERC Budget includes funding for this project.

NAESB Involvement in Parallel Flow Proposal

- The NAESB Annual Plan included a line item on Future Path of TLR. An accompanying white paper described two phases of this initiative:
  - The first phase involves enhancements to the TLR reporting process to provide near real-time GTL reporting by all RCs in the EI similar to MISO, PJM and SPP.
  - The second phase involves enhancements to the TLR curtailment process to replace the “share the pain” approach with an approach that is more efficient in managing congestion. The second phase is dependant on completion of the first phase.
- The line item in the NAESB 2008 Annual Plan was carried forward into the NAESB 2009 Annual Plan.

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NAESB Involvement in Parallel Flow Proposal

- The NAESB BPS has been working on a mechanism that assigns the GTL priorities used in the IDC.
- The NAESB BPS is working on concepts that would be applicable to jurisdictional entities, non-jurisdictional entities and Canadian entities.
- The NAESB BPS will work jointly with the IDCWG such that the mechanism used to assign GTL priorities is consistent with the calculations in the IDC.

General Timeline for Parallel Flow Proposal

- The IDCWG will not finalize this timeline until after a vendor has been selected and there is a commitment by the ORS to move forward with this project.
  - It is expected that a vendor will be recommended and the NERC ORS will approve the recommendation at their Nov 2009 meeting.
  - It is expected that the IDCWG will oversee IDC software development in parallel with the NAESB BPS working on prioritization in spring and summer 2010.
  - It is expected that by Sept 2010, will start parallel operation in staging environment. Will run in this mode anywhere from 3 to 6 months to evaluate results while benchmarking against current NNL calculation. The visualization features will be available while in staging environment.
  - It is expected that no later than summer 2011, will implement new software and rely on this process to assign relief obligations during TLR.

Parallel Flow Visualization/Mitigation Proposal

➢ Questions?

Parallel Flow Visualization/Mitigation Proposal

Attachment

Parallel Flow Proposal Motion Approved on May 6, 2009

- . . . moved that the ORS agrees that the future use of GTL impacts, as identified in the MISO, PJM, and SPP "Generation-to-Load Reporting Requirements" white paper, will improve visibility and as such will enhance reliability of the Eastern Interconnection. The ORS believes the IDC should be modified to accept GTL calculations. The GTL impact calculation should be consistent for all EI RCs and, as such, a single vendor should be selected to implement the methodology and to perform the actual calculations for all EI RCs.
- These changes are intended to provide information only at this point (i.e. providing the calculated GTL impacts without changing the functionality of the tools) until the ORS agrees that it is appropriate to utilize the additional data to enhance tool processes or possible changes to TLR procedures. It is recognized that any changes to the TLR process to utilize the additional data made available as a result of this initiative will be determined preferably by the existing joint NAESB/NERC TLR SDT. Industry support will be critical to the success of this initiative and will be best achieved by ensuring appropriate industry input and transparency in the decisions taken.

Parallel Flow Proposal Motion Approved on May 6, 2009

- The ORS directs the IDCWG to take the following actions:
  - Identify the minimum data set required to achieve the required calculations by the September 2009 ORS meeting.
  - Identify the required changes to the IDC to identify the GTL impacts
  - Recommend a vendor to perform the GTL calculations for all EI RCs
  - Determine, in cooperation with the vendor, the GTL calculation methodology.
  - Identify to the ORS any additional items that are required to incorporate GTL impacts
- The IDCWG should target having proposed recommendations to the ORS for the November 2009 meeting.
- The GTL impacts should be archived in the IDC for an initial period of 12 to 18 months to allow analysis to be performed to assess the potential impact of any proposed changes to the TLR process including the possible use of near real time data for NNL calculations and possible use of near real time data for other TLR calculations as determined by NAESB. Process changes may be incorporated before the completion of the analysis period if the ORS determines it is appropriate.

Parallel Flow Proposal Motion Approved on May 6, 2009

- In addition, the NERC ORS will develop reliability metrics to confirm that the Generation-to-Load calculation is an improvement in accuracy over the static NNL calculation which must be met before changing to using the Generation-to-Load calculated impacts for TLR.

Buy-Through of Congestion

Robert Pike – NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

Buy-Through of Congestion

- Benefits
  - *Buy-Through of Congestion provides for the recovery of congestion management costs incurred in managing loop flow impacts.*
    - Provides for an alternative to market and operational interruptions caused by Transmission Loading Relief (TLR) actions by establishing an economic based alternative to imposed curtailments.
    - More efficient utilization of the transmission network.
    - More consistent transaction scheduling decisions with regional prices.

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Buy-Through of Congestion

- Concept
  - *Parties scheduling transactions with any of the other ISO/RTOs surrounding Lake Erie would be billed for the real-time congestion costs incurred by neighboring systems supporting the loop flow created by the transaction to maintain the schedule.*
    - Sources of loop flow identified via the NERC IDC tools
    - Congestion costs captured by regions LMP prices.
    - Allocate costs to the transaction schedules in proportion to the schedules loop flow impacts
    - Exposure to congestion costs can be hedged with existing Day-Ahead transmission scheduling processes, or avoided with real-time scheduling processes

Buy-Through of Congestion

- Parallel Flow Visualization
  - *Provides single common source and methodology for isolating sources of flow.*
    - Identify sources of flowgate impact, included Balancing Authority to Balancing Authority interchange schedules, and intra-regional generation-to-load impacts.
    - Incorporates state of phase angle regulator controls.
  - *Market visibility of impacts available through the NERC IDC or OATi tools.*
  - *Loop flow impacts calculated by IDC will reflect the ability (or lack thereof) of the PARs to maintain actual flow consistent with scheduled flow.*

Buy-Through of Congestion

- Responsible Control Area (RCA)
  - *Define RCA as the sink balancing area or the last control area of the four Lake Erie ISOs to be engaged in a transaction.*

Buy-Through of Congestion

- Biddable Options
  - *Provide capability at bid submission for market participant to identify whether they are willing to pay, or not willing to pay, for congestion charges caused by their off-control path flow impacts*
    - Transactions that indicate they are not willing to pay congestion will be curtailed when congestion detected and flowgate impacted by the transactions loop flow. Those transactions will not be charged for congestion related impacts.

Buy-Through of Congestion

- Biddable Options
  - *There will not be an option to specify an "up-to" congestion charge value. Implementation not viable given the:*
    - Dynamic nature of markets in establishing market clearing prices;
    - Complexity of multiple ISOs engaged in applying congestion charges for loop flow impacts, and the;
    - Operational uncertainty associated with continuously adjusting interchange values.

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Buy-Through of Congestion

- Transaction Removal Process
  - *A monitoring ISO that encounters congestion, will:*
    - Determine impact on flowgate from loop flows
    - Identify the transaction schedule sources of the loop flows
    - Coordinate with the RCA(s) of transactions identified.
  - *The RCA(s) will:*
    - Review the set of transactions and curtail the set that is not willing to pay congestion costs. This set will not be billed for congestion charges.
    - Communicate with the monitoring ISO upon completion of review and curtailment.
- Throughout the process, TLR procedures remain as an alternative to the monitoring ISO to address system overloads.

Buy-Through of Congestion

- Transaction Re-Instatement Process
  - *Applicable after a transaction has been curtailed due to not be willing to pay for congestion costs.*
  - *An RCA will not re-initiate transaction schedules (or add new transaction schedules) that have an indication they are not willing to pay for congestion costs if scheduling the transaction would increase loop flows on an active flowgate.*
    - An RCA can initiate transaction schedules that have indicated they are willing to pay for congestion costs associated with their loop flow impacts.
  - *A monitoring ISO will continue to evaluate congestion on the original flowgate and notify the RCA(s) when the constraint is relieved.*
    - Notification will be provided in advance of the bottom of the hour for next hour scheduling changes, consistent with TLR procedures.

Buy-Through of Congestion

- Settlement of Allocated Charges
  - *The monitoring ISO will determine the congestion costs to be recovered based upon NERC IDC tools to identify transaction and their respective impact on the constrained flowgates and LMP calculations of constraint cost and will provide the costs to the respective RCA(s).*
  - *The RCA(s) will apply charges to specific transactions as part of their normal billing procedures, collect revenue, and return revenue to the monitoring ISO.*

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Buy-Through of Congestion

- Settlement of Allocated Charges
  - *Loop flows having a counter-flow impact on prevailing flows will produce lower net flows and lower constraint management costs, thereby lowering the costs to be recovered from prevailing flow loop flows.*
  - *Counter-flow transaction will not be compensated for the relief they provide via Buy-Through of Congestion.*
  - *Counter-flow transactions must be explicitly represented into the ISO-market that is expected to benefit from the transaction in order to receive the compensation.*

Buy-Through of Congestion

- Responsible Control Area (RCA)
  - *Responsibilities include:*
    - Collecting bidding indicators of willingness to pay congestion;
    - Manage transaction schedules in response to identification by monitoring control area of transactions impact and occurrence of flowgate constraints;
    - Process, collect and distribute settlement charges.
  - *RCA(s) settlement necessary as all market participants may not be members of all market areas.*

Buy-Through of Congestion

- Monitoring ISO
  - *Responsibilities include:*
    - Monitoring for flowgate congestion impacted by loop flow resulting from transaction schedules;
    - Coordinate with RCA(s) to identify and review transaction schedules impacting flow gates;
    - Release flowgate transaction scheduling restrictions;
    - Calculate and communicate congestion charges to RCA(s) for transaction impacts.

NEW YORK INDEPENDENT SYSTEM OPERATOR

Buy-Through of Congestion

- Managing Congestion Cost Exposure
  - *NYISO: Up-to congestion product available in DA. Opportunities to expand virtual trading to the proxy bus locations.*
  - *PJM: Up-to congestion product available in DA. 20-minute advance notice schedule termination. Virtual bidding options available.*
  - *MISO: Up-to congestion product available in DA. 20-minute advance notice schedule termination. Virtual bidding options available.*
  - *IESO: No products currently available.*

Buy-Through of Congestion

- Example
  - *A 100 MW transaction from IESO to PJM, via MISO. The transaction has indicated they are willing to pay for congestion costs.*
  - *Transaction is submitted, reviewed and scheduled through the standard ISO/RTO processes.*
  - *The OH-Michigan PARs are operated and control schedule to 90 MWs. 10 MWs remain flowing through NY as loop flow (10% of the transaction schedule).*
  - *A flow gate within NY becomes constrained at xx:30 of the hour. The flowgate is impacted by the loop flows.*
  - *The resulting congestion cost is $10/MWhr.*
  - *The transaction would receive a buy-though of congestion settlement of:*

    (10%)(100 MW)*(0.5 hour)*($10) = $50 (or $0.50/MWhr)*

Congestion Management

Stan Williams - PJM

PJM & Midwest ISO Market-to-Market Coordination

Broader Regional Markets

Joint Stakeholder Meeting

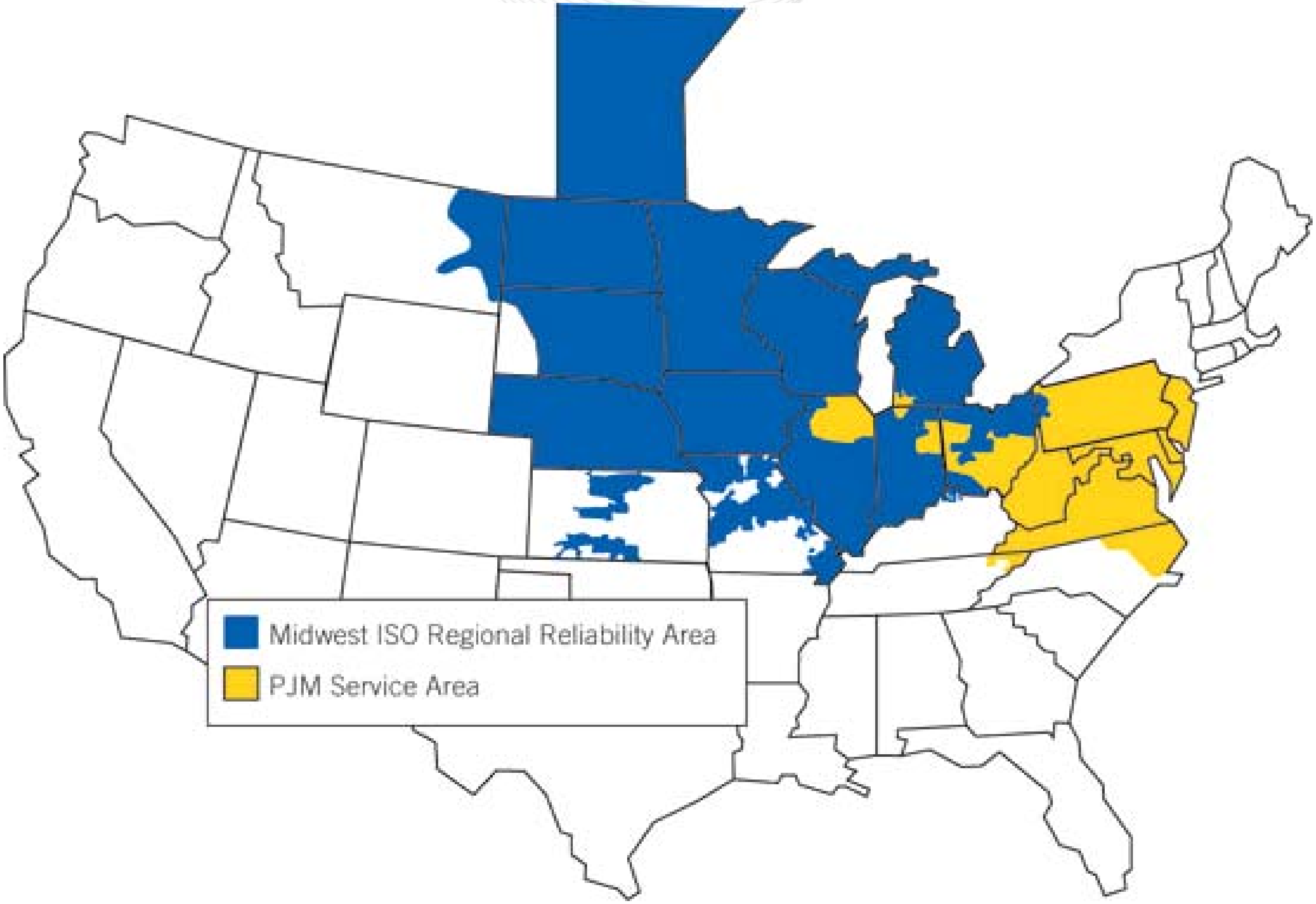
October 29, 2009

Agenda

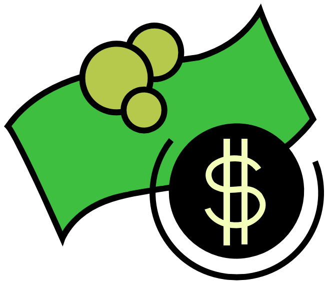
Market-to-Market Coordination

- Objectives
- Overview
- Example
- Results

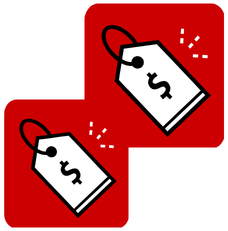
PJM and Midwest ISO Service Area



Objectives of Market-to-Market Coordination



- Achieve the least cost redispatch solution for coordinated constraints across multiple systems.



- Provide a more <u>consistent pricing</u> profile across the two markets.
- Enhance <u>system reliability</u> by pooling resources from both RTOs to jointly control transmission constraints near the RTO border.

Market-to-Market Coordination Overview

- When the monitoring RTO (MRTO) controls a reciprocal coordinated flowgate (RCF) in its real-time dispatch system, it will initiate the Market-to-Market coordination process with a relief MW request.
- The non-monitoring RTO (NMRTO) will respond by adjusting the RCF limit using the desired relief request from the MRTO and redispatching its generation to control the RCF to either

  (a) provide the relief requested by the monitoring RTO;

  (b) redispatch up to the current shadow price from the MRTO.

Market-to-Market Coordination Overview (cont'd)

- As the relief provided by the NMRTO is realized in the RCF, the MRTO can control the RCF at a lower shadow price. The updated shadow price is sent to the NMRTO.
- Both RTOs will then continue to redispatch their systems respecting the constrained flowgate.
- The result of this coordination will be a cost effective redispatch solution for the combined footprint.
- The RTOs will then compensate each other for the redispatch provided based on the real time market flow of the NMRTO comparing to the historic usage.

Market-to-Market Coordination Example

Market-to-Market Example – Stage 1

Midwest ISO
System Price $40

PJM (Monitoring RTO)
System Price $40

LOAD Y
+15% Dfax
LMP = $40

LOAD X
+15% Dfax
LMP = $40

GEN 3
$60 Offer; - 20% Dfax
0 MW (Max 20)
LMP = $40

MISO MF = 35

GEN 2
$58 Offer; - 30% Dfax
0 MW (Max 20)
LMP = $40

GEN 1
$22 Offer; +32% Dfax
200 MW (Econ min 100)
LMP = $40

Flowgate A
100 MW
(limit 100)

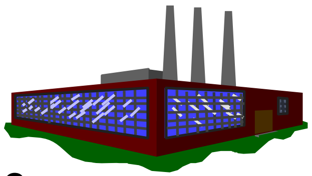
LOAD X (in PJM) and LOAD Y (in Midwest ISO) are electrically close to each other and have the same impact on Flowgate A.

The initial Midwest ISO Market Flow on Flowgate A is 35 MW.

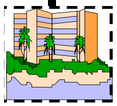
Market-to-Market Example – Stage 2a

Midwest ISO
System Price $40

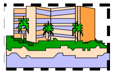
PJM (Monitoring RTO)
System Price $40



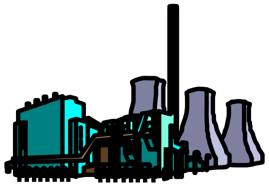
GEN 3
$60 Offer; - 20% Dfax
0 MW (Max 20)
LMP = $40



LOAD Y
+15% Dfax
LMP = $40

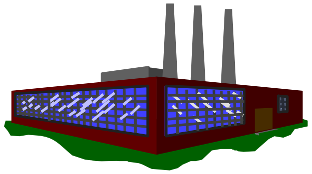


LOAD X
+15% Dfax
LMP = $40



GEN 1
$22 Offer; +32% Dfax
200 MW (Econ min 100)
LMP = $40

Flowgate A
110 MW
(limit 100)



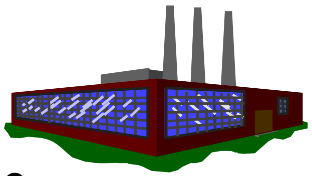
GEN 2
$58 Offer; - 30% Dfax
0 MW (Max 20)
LMP = $40

The flow on Flowgate A increases to 110 MW due to higher load in PJM

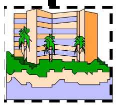
Market-to-Market Example – Stage 2b

Midwest ISO
System Price $40

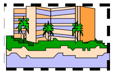
PJM (Monitoring RTO)
System Price $40



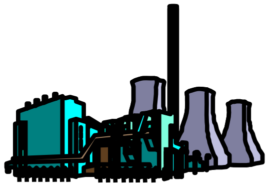
GEN 3
$60 Offer; - 20% Dfax
20 MW (Max 20)
20 * 0.2 = 4 MW of relief



LOAD Y
+15% Dfax
LMP = $40

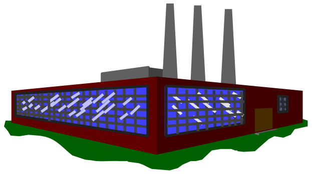


LOAD X
+15% Dfax



GEN 1
$22 Offer; +32% Dfax
200 MW (Econ min 100)
LMP = $40

Flowgate A
110 MW
(limit 100)



GEN 2
$58 Offer; - 30% Dfax
20 MW (Max 20)
20 * 0.3 = 6 MW of relief

PJM dispatches GEN 2 and GEN 3 to control the Flowgate A

Market-to-Market Example – Stage 2c

Midwest ISO
System Price $40

PJM (Monitoring RTO)
System Price $40
Shadow Price = - 100

★ GEN 3
$60 Offer; - 20% Dfax
20 MW (Max 20)
20 * 0.2 = 4 MW of relief
LMP = $60

LOAD Y
+15% Dfax
LMP = $40

LOAD X
+15% Dfax
LMP = $25

GEN 1
$22 Offer; +32% Dfax
200 MW (Econ min 100)
LMP = $40

Flowgate A
100 MW
(limit 100)

GEN 2
$58 Offer; - 30% Dfax
20 MW (Max 20)
20 * 0.3 = 6 MW of relief
LMP = $70

PJM dispatches GEN 2 and GEN 3 to control the Flowgate A
GEN 3 is the marginal unit and constraint shadow price is (60-40)/(-.2)=-100
GEN 2 LMP = 40 +(-0.3 * -100) = $70; LOAD X LMP = 40 + (0.15 * -100) = $25

Market-to-Market Example – Stage 3a

Midwest ISO

System Price $40

PJM (Monitoring RTO)

System Price $40

Shadow Price = - 100

GEN 3

$60 Offer; - 20% Dfax

20 MW (Max 20)

20 * 0.2 = 4 MW of relief

LMP = $60

LOAD Y

+15% Dfax

LOAD X

+15% Dfax

LMP = $25

GEN 2

$58 Offer; - 30% Dfax

20 MW (Max 20)

20 * 0.3 = 6 MW of relief

LMP = $70

GEN 1

$22 Offer; +32% Dfax

Flowgate A

100 MW

(limit 100)

PJM notifies Midwest ISO to invoke M2M to control Flowgate A.

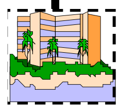
PJM requests 4 MW of relief at the current shadow price of -100.

Midwest ISO reduces GEN 1 to provide the relief requested by PJM

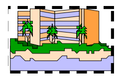
Market-to-Market Example – Stage 3b

Midwest ISO
System Price $40
Shadow Price = - 56.25

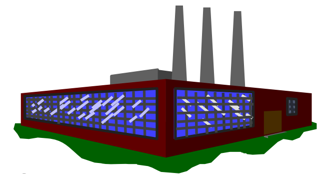
PJM (Monitoring RTO)
System Price $40
Shadow Price = - 100



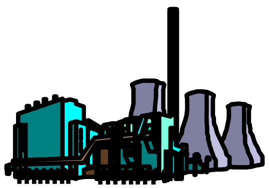
LOAD Y
+15% Dfax
LMP = $31.6



LOAD X
+15% Dfax
LMP = $25



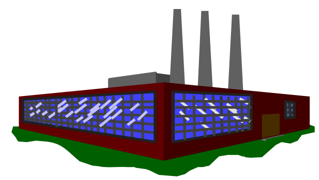
★ GEN 3
$60 Offer; - 20% Dfax
20 MW (Max 20)
20 * 0.2 = 4 MW of relief
LMP = $60



★GEN 1
$22 Offer; +32% Dfax
187.5 MW (Eco min 100)
12.5 * 0.32 = 4 MW of relief
LMP = $22

MISO MF = 31

Flowgate A
96 MW
(limit 100)



GEN 2
$58 Offer; - 30% Dfax
20 MW (Max 20)
20 * 0.3 = 6 MW of relief
LMP = $70

GEN 1 is reduced by 12.5 MW (to 187.5 MW) to provide 4 MW of relief.
Midwest ISO constraint shadow price is (22-40) / 0.32 = - 56.25
LOAD Y LMP = 40 + (0.15 * - 56.25) = 31.6

Market-to-Market Example – Stage 4a

Midwest ISO
System Price $40
Shadow Price = - 56.25

PJM (Monitoring RTO)
System Price $40

LOAD Y
+15% Dfax
LMP = $31.6

LOAD X
+15% Dfax

GEN 3
$60 Offer; - 20% Dfax
0 MW (Max 20)
0 * 0.2 = 0 MW of relief

GEN 1
$22 Offer; +32% Dfax
187.5 MW (Eco min 100)
12.5 * 0.32 = 4 MW of relief
LMP = $22

Flowgate A
100 MW
(limit 100)

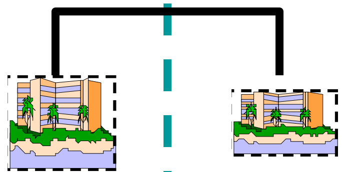
GEN 2
$58 Offer; - 30% Dfax
20 MW (Max 20)
20 * 0.3 = 6 MW of relief

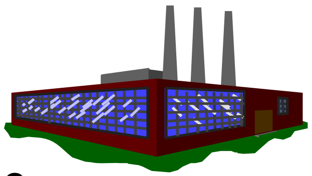
With loading decreases on Flowgate A, PJM can release the less cost-effective GEN 3.

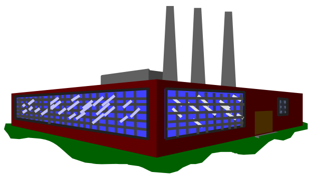
Market-to-Market Example – Stage 4b

Midwest ISO
System Price $40
Shadow Price = - 56.25

PJM (Monitoring RTO)
System Price $40
Shadow Price = - 60



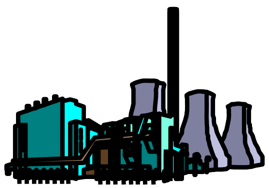


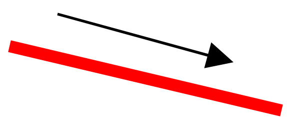


LOAD Y
+15% Dfax
LMP = $31.6

LOAD X
+15% Dfax
LMP = $31

GEN 3
$60 Offer; - 20% Dfax
0 MW (Max 20)
0 * 0.2 = 0 MW of relief
LMP = $52





GEN 1
$22 Offer; +32% Dfax
187.5 MW (Eco min 100)
12.5 * 0.32 = 4 MW of relief
LMP = $22

Flowgate A
100 MW
(limit 100)

GEN 2
$58 Offer; - 30% Dfax
20 MW (Max 20)
20 * 0.3 = 6 MW of relief
LMP = $58

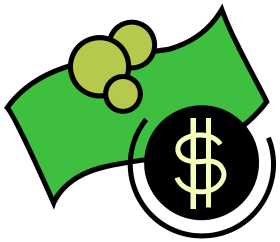
With GEN 3 offline, GEN 2 becomes the new marginal unit for the constraint
Constraint shadow price is (58 - 40) / (- 0.3) = - 60
GEN 3 LMP = 40 + (- 0.2 * - 60) = 52; LOAD X LMP = 40 + (0.15 * - 60) = 31

Market-to-Market Coordination Results

What have been the Market-to-Market Results?

PJM has observed the following:

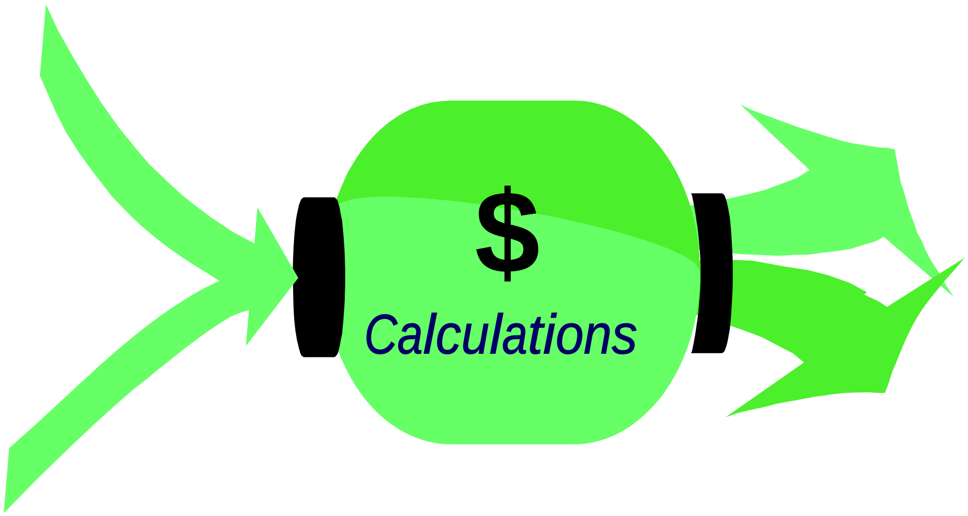
- Lower congestion cost: The redispatch cost for the PJM market would have been higher if PJM had to control all transmission constraints on its own.



- More consistent pricing across the RTO border: When the market-to-market coordination is in effect, the prices at the Midwest ISO and PJM border converge better than before.

- More Reliable operation: Since economic generation in Midwest ISO is now available for constraint control, PJM has experienced fewer emergency transmission operations.

Market-to-Market Coordination Example – Settlement Calculations



Market-to-Market Settlement Calculations

(assuming Stage 4 from the example went on for one full hour)

Scenario 1 : Midwest ISO is below the **Network and Native Load (NNL*)**

NNL for Midwest ISO on Flowgate A per the example = 40MW
Real-Time Market Flow MW by Midwest ISO on Flowgate A
= 31MW (requested by PJM)
Midwest ISO Shadow Price on Flowgate A = -$56.25/MWh

Payment (PJM to Midwest ISO) = (NNL – Real-Time Marketflow) * Transmission Constraint Shadow Price in Non-Monitoring RTO's Dispatch Solution

Payment (PJM to Midwest ISO) = (40/MWh-31/MWh) * -$56.25/MWh

Payment (PJM to Midwest ISO) = -$506.25

*** Midwest ISO NNL on Flowgate A is the Midwest ISO generation-to-load impact on Flowgate A (in PJM) based on historic usage.**

Market-to-Market Settlement Calculations (cont'd)

Scenario 2: Midwest ISO is above the Network and Native Load (NNL)

NNL for Midwest ISO on Flowgate A per the example = 28MW
Real-Time Market Flow MW by Midwest ISO on Flowgate A
= 31MW (requested by PJM)
PJM Shadow Price on Flowgate A = -$60/MWh

Payment (Midwest ISO to PJM) = (NNL – Real-Time Marketflow) * Transmission Constraint Shadow Price in Monitoring RTO's Dispatch Solution

Payment (Midwest ISO to PJM) = (28/MWh-31/MWh) * -$60/MWh

Payment (Midwest ISO to PJM) = $180

Interregional Transaction Coordination

Robert Pike - NYISO

Interregional Transaction Coordination

- Benefits
  - *In-hour transaction scheduling lowers total system operating costs through improved consistency of transaction schedules with market-to-market price patterns.*
  - *Expand pool of flexible assets to balance intermittent power resources output.*
  - *Improve price consistency and transmission utilization across markets.*
  - *Address uncertainty in forward looking scheduling horizons.*

Interregional Transaction Coordination

- Concept
  - *Allow Market Participants to provide flexible energy, reserve and regulation transaction bids, where the real-time dispatch tools will evaluate these flexible transactions on an intra-hour basis.*
  - *Phase 1 – Adjust HQ energy interchange on a 5-minute frequency based upon NY economic evaluation of flexible bids.*
    - Pre-coordination of flexible bids and automated coordination of energy schedules necessary to support frequency of interchange adjustments.

Interregional Transaction Coordination

- Future Steps
  - *Phase 2 – Establish market and coordination processes to support purchase and sale of reserve and regulation between markets.*

Interregional Transaction Coordination

- Future Steps
  - *Phase 3 – Define process to apply dynamic scheduling between two market systems.*
    - Creation of new "spread" bid product.
      - Market Participant supplies single bid to be used by both neighboring ISOs, indicating desired profitability for transaction.
      - ISO uses current/forecasted prices to schedule transactions. Select spread bids with lower bid than predicted difference between market prices.
      - ISOs incorporate updated transaction schedules into dispatch tools.
      - Process is repeated at defined intervals.
    - Market participant assumes risk of final prices being different than those used in scheduling decisions.

Next Steps

Rana Mukerji – NYISO

*Implementation Timeline**

- Parallel Flow Visualization
  - *Software Ready / Parallel Operations* — *2010*
- Buy-Through of Congestion
  - *Design Development* — *2010*
  - *Implementation* — *2011*
- Congestion Management
  - *PJM-NYISO Implementation* — *2011*
  - *Extend to Additional Regions* — *2012*
- Interregional Transaction Coordination
  - *Energy Scheduling with NY/HQ* — *2010*
  - *Extend to Additional Regions* — *2011-12*

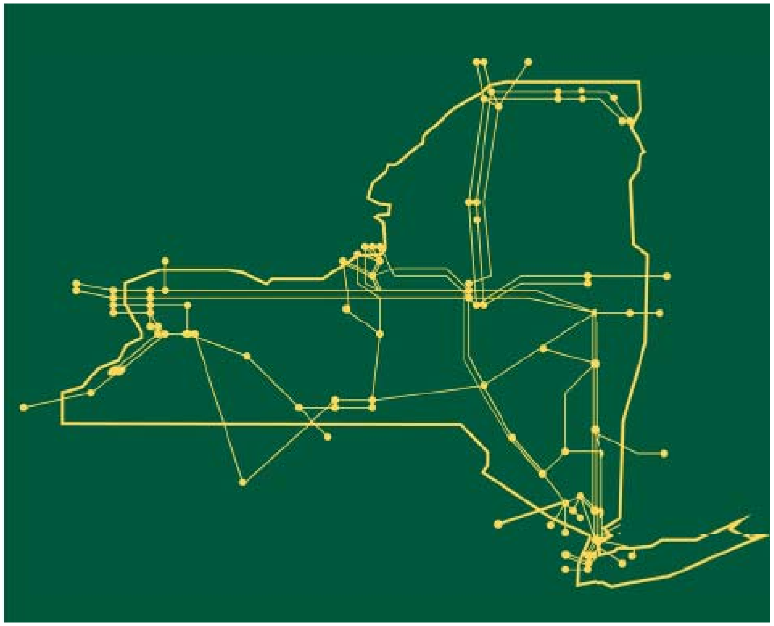
**Prospective timeline pending design development and approval from Market Participants, neighboring Control Areas and the Commission.*

Ongoing Efforts

- **Request feedback to rpike@nyiso.com by November 13, 2009 or through each ISO's stakeholder discussion.**
  - *Follow-up Joint Stakeholder meeting in December*
- **Ongoing Solution and Schedule Development**
  - *MIWG: September – December, 2009*
  - *Joint ISOs: August – December, 2009*
  - *Joint Stakeholder Meetings: October, December, 2009*
  - *BIC: Concept Review – December 9, 2009*
  - *FERC: Response – January 12, 2010*
- **Design and Stakeholder Approvals**
  - *Detailed design, Joint Operating Agreements and tariff development beginning in 2010*

NEW YORK INDEPENDENT SYSTEM OPERATOR

The New York Independent System Operator (NYISO) is a not-for-profit corporation that began operations in 1999. The NYISO operates New York's bulk electricity grid, administers the state's wholesale electricity markets, and conducts comprehensive planning for the state's bulk electricity system.



www.nyiso.com

Attachment D

Overview of Proposed Inter-Area Coordination Between ISO New England and New York ISO

Inter-Area Coordination between ISO New England and New York ISO

1. Introduction

ISO New England (ISO-NE) and New York ISO (NYISO) are committed to removing barriers to a broader regional market and improving the efficiency of electricity exchange between our markets. To that end, over the last several months, staff from ISO-NE and NYISO have met to explore a package of joint operational coordination measures and market design changes. The shared objective is to improve the economic utilization of the transmission ties and leverage the region's capabilities to minimize out-of-market actions.

The initiatives identified are:

- Interregional Transaction (Scheduling) Coordination; and
- Market-to-Market (Congestion Management) Coordination

The following plan presents the high-level scope of work, major milestones and schedule for a multi-phased project that will improve the efficiency of the energy markets and transmission system utilization on a regional basis.

2. Scope

(a) <u>Interregional Transaction (Scheduling) Coordination</u>

Currently ISO-NE and NYISO clear and schedule transactions using separate and independent mechanisms. For example, the NYISO market allows transactions to be submitted up to 75 minutes before the start of the transaction, and all transactions must have a price. The ISO-NE market allows transactions to be submitted 60 minutes before the start of the transaction, but to submit in this timeframe the transactions must be self-scheduled (price-takers). At a high level, the result of the differences in external transaction rules is that NYISO clears real-time transactions before ISO-NE, using bid and offer information entered into its market system. This clearing generates a set of available transactions. Then ISO-NE clears transactions in its market system and compares that set of cleared transactions to the set of transactions previously cleared by NYISO. Those cleared in both markets can be scheduled to flow in the hour.

The Interregional Transaction Coordination component of the proposed project constitutes the first major phase of work. The objective of this phase is to design, build and implement a joint transaction scheduling system that accepts transactions and clears them simultaneously based upon the expected prices in the regions, thereby creating a set of transactions and net tie schedule for each hour in a single pass. It is envisioned that initially transactions will be scheduled hourly, as is done today, and subsequently will allow for intra hour scheduling.

In addition to working out the market design changes and the associated market clearing function, the project design team will have to determine and answer several questions related to the software infrastructure, such as whether a new software system is required to receive and process transactions, how and where the required information is collected and the modeling of each area's operating protocols and scheduling rules.

(b) Market-to-Market (Congestion Management) Coordination

An interconnected transmission network provides benefits of improved operational reliability and redundancy. The re-dispatch of generators within a neighboring control area may address transmission constraints more cost effectively than the re-dispatch of generators or other control action within the monitoring control area. A congestion management protocol allows for the inter-control area dispatch to manage the congestion (at a lower overall resulting cost) and the appropriate settlement of those actions.

The purpose of this congestion management function is to

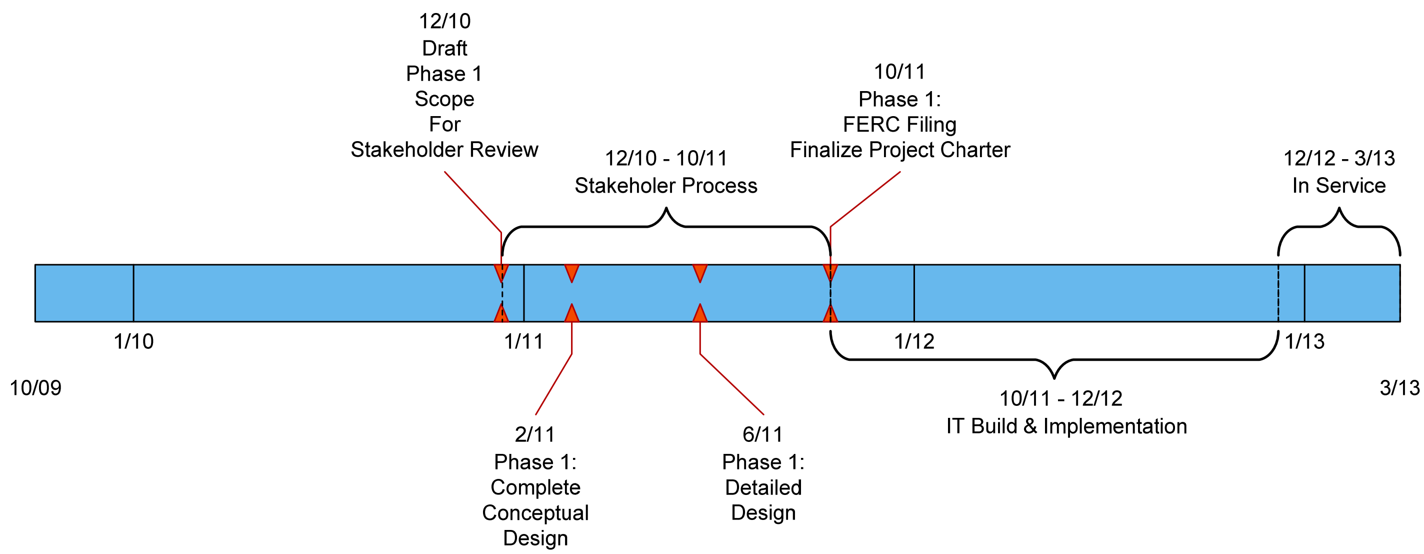
(a) Pre-identify constraints that multiple control areas can address through re-dispatch actions;
(b) Develop an agreed to baseline of allowable usage of each control area's transmission network; and
(c) Establish data sharing protocols to communicate real-time constraint management costs

Market-to-Market Coordination is intended to ensure cost effective utilization of the regions' collective assets to address constraints across multiple systems, with the goal of lowering overall congestion costs to consumers.

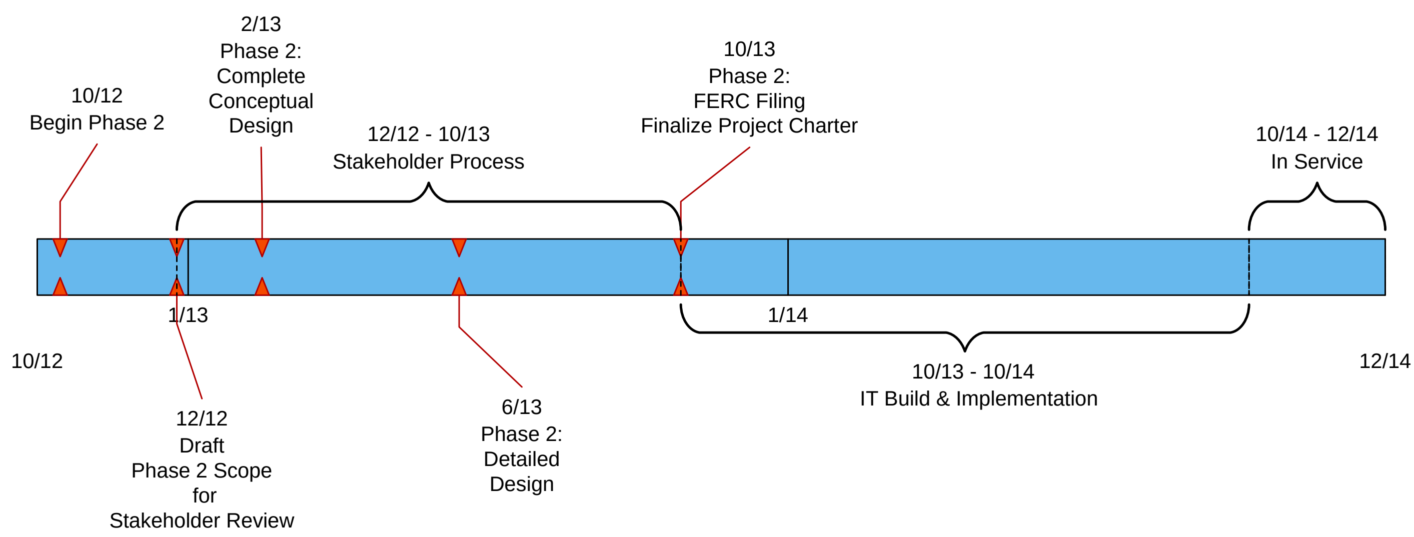
3. Schedule

Based on current priorities for ISO-NE, the plan is to implement the project in two phases starting in the fourth quarter of 2010. Phase I is focused on Interregional Transaction Coordination and Phase II is focused on Market-to-Market (Congestion Management) Coordination. Furthermore, the two phases are designed to be in sequential order rather than in parallel. This is to ensure that resources are sufficiently available to deliver the two phases in a successful manner.

Phase 1: Interregional Transaction (Scheduling) Coordination



Phase 2: Market-to-Market (Congestion Management) Coordination



4. Milestones

For the Phase I (Interregional Transaction Coordination) and Phase 2 (Congestion Management Coordination) projects, the following preliminary high-level milestones are identified.

Milestones	Target Dates for Phase I	Target Dates for Phase II
Draft Scope for Stakeholder Review	12/10	12/12
Conceptual Design	2/11	2/13
Detailed Design	6/11	6/13
Filing with FERC and Finalize Project Charter	10/11	10/13
Software and Business Procedures Completed	10/11 - 12/12	10/13 - 10/14
In Service	12/12 - 3/13	10/14 - 12/14

5. Roles, Responsibilities, and Staffing

The project leads for this multi-year effort will be Robert Laurita for ISO-NE and Robert Pike for NYISO. ISO-NE and NYISO market development staffs will work jointly to design the components of the project. The project leads will provide necessary liaison with needed subject matter experts within each organization. As the project scope evolves, specific roles will be established and resource assignments will be made to ensure deliverables are produced consistent with the above mentioned project milestones and schedule.

6. Budget and Project Charters

The budget and project charter for this project will depend on the final scope of work and specified requirements. Both ISO-NE and NYISO expect that Phase I of this project is larger in scope than Phase II and will require a higher budget. Both phases of the project are dependent on appropriate funding in the operating and capital budgets from 2010 to 2014. Project charters for each phase (containing detailed scope, budget and a resource plan) will be prepared at the culmination of the stakeholder review process for each phase.

7. Risks

This project is a multi-year endeavor that will require the dedicated commitment of both NYISO and ISO-NE staff to this project over multiple years. This project will compete with other priorities for human and financial resources. In the case of ISO-NE, current major priorities include the design of enhancements to the Forward Capacity Market (FCM) and Price Responsive Demand. Furthermore, both RTOs will have to respond to any FERC initiatives that may arise during the project life cycle. In the event that major priorities arise beyond those that have already been identified and planned for, ISO-NE and NYISO management might need to revisit the project schedule. If resources free up from FCM and other previously committed projects, it may be possible to accelerate the projects identified in this document.

Attachment E

Letter from ITC Holdings to NYISO
Dated December 23, 2009

ITC HOLDINGS CORP.
27175 Energy Way • Novi, MI 48377
phone: 248.946.3000
www.itctransco.com

December 23, 2009

Rana Mukerji
Vice President, Market Structures
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144

Dear Mr. Mukerji:

In response to your December 16, 2009 inquiry regarding the implementation status of the Ontario-Michigan phase angle regulators ("PARs"), please be advised that International Transmission Company d/b/a ITC*Transmission* ("ITC") has installed new PARs at its Bunce Creek Station in Marysville, Michigan. In coordination with Hydro One Networks, Inc. ("Hydro One"), the owner of the Canadian interface facilities, a fiber optic communication system is now being installed. ITC has been informed that this work will be completed during the first quarter of 2010, at which time the Ontario-Michigan PARs will be physically ready to go into service.

Despite the physical status of the facilities, there is a substantial impediment which if not promptly resolved, will delay activation of the PARs. Specifically, as stated in ITC's comments on the draft loop flow report recently circulated by the New York Independent System Operator Inc. ("NYISO"), it is clear that ITC's PARs, by helping to control loop flow around Lake Erie, will provide substantial benefits to the entire surrounding region. Nevertheless, under the current rate structure, when the PARs are activated, their capital costs and their maintenance and operations expenses – approximately $8 million per year – will be borne entirely by consumers in the State of Michigan, specifically, only the transmission customers of ITC. Consumers in the other markets surrounding the lake will receive substantial benefits, but will bear none of the costs.

ITC believes that it is essential that the costs of the PARs be shared more broadly by the beneficiaries and it has attempted to work with NYISO, the Midwest Independent Transmission System Operator, Inc. ("MISO") and others to develop a reasonable cost sharing plan. An agreement has not yet been reached, however, and ITC has, in fact, been quite disappointed by the seeming lack of commitment of these parties to reach such an agreement. Until substantially more progress is made on the cost sharing issue, ITC will be unable to execute the various necessary operating agreements for the PARs – which are otherwise in final form – and the Department of Energy will, accordingly, not be in a position to approve the pending amendment to ITC's Presidential Permit which is required to place the PARs into service.

ITC regrets this potential delay in placing the PARs into service and it remains ready and willing to devote whatever resources are necessary to working with NYISO, MISO and other interested parties to develop an acceptable cost sharing plan as a promptly as possible. In these difficult economic times, however, ITC is not willing to saddle Michigan consumers with the full costs of these facilities, so until substantial progress is made on the cost sharing issue, activation of the PARs will not be possible.

Please contact me if you have any questions or further thoughts on this issue.

Very truly yours,

Thomas H. Wrenbeck
Director, Regulatory Strategy

Attachment F

Northeast ISO Seams Resolution Report for the Third Quarter of 2009, Issued October 19, 2009

October 19, 2009

Northeast ISOs
Seams Resolution Report
History of Seam Issues Resolution

Broader Regional Markets

P9 LAKE ERIE SYSTEM REDISPATCH PROJECT IMPLEMENTATION
This NPCC procedure allows the redispatch of suppliers across regions to alleviate the potential curtailments of transactions due to TLR requests whenever a control area is in an energy short situation. The project requires implementation of operating procedures and billing and settlement process to account for the regional redispatch.

- PJM, NYISO, MISO, and IESO have finished analyzing the causes of high circulating flows and have provided a report with recommendations http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf.

- The second phase of PJM and MISO's loop flow study to identify the sources of high circulation on specific flowgates was completed in November 2008. This study report and presentation materials can be found at http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-loop-flow-phase-ii-study-report-final-20081112.pdf and http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-item-3c-loop-flow-phase-ii-study-presentation-v3.pdf.

- This project has been moved to the closed list. P36 *Long Term Solution for Lake Erie Loop Flows* is being used to report on efforts to develop solutions to mitigate Lake Erie loop flows. (Q3-2009)

P15 REGIONAL RESOURCE ADEQUACY MODEL (RAM) GROUP
The Regional Resource Adequacy Model (RAM) Working Group (formerly the JCAG Working Group) was set up to develop longer-range UCAP markets in NY, PJM and ISO-NE than currently exist. The RAM Working Group developed initial recommendations in mid-2002. The work plan was reassessed in light of the SMD NOPR and the ISOs/RTOs filed joint comments addressing resource adequacy on January 10, 2003. The comments described a central market-based resource adequacy framework, which was consistent with the goals of the SMD NOPR. NERA was selected to analyze the proposed central resource adequacy market design, and presented their final report at the February 26 regional RAM meeting. A NYISO status report was filed with FERC on February 27, 2004. The broad range of concerns raised by stakeholder groups in each ISO/RTO make it unlikely that all of the ISO/RTOs would adopt the RAM proposal as it was then currently formulated. It was anticipated that this effort would lead, instead, to enhancements in the capacity markets in each region. In enhancing their existing markets, the ISO/RTOs have committed to maintain the ability to trade the same product (UCAP) between regions and to identify and remove any remaining barriers to the trading of capacity between regions. Each region has Resource Adequacy/ICAP working groups looking at this issue.

- The NYISO submitted a hybrid proposal to its stakeholders for consideration which incorporates a voluntary forward capacity market for procurement of a portion of its future resource requirements.

- On June 16, 2006, the Commission issued an order approving the proposed capacity market settlement agreement for the New England region, which provides for the eventual implementation of a forward capacity market after an interim transition period that begins on December 1, 2006.

- PJM introduced a proposal for a Reliability Pricing Model ("RPM") in June 2004 and has subsequently presented and revised the proposal at numerous stakeholder meetings. The proposal has been presented and discussed with its Members Committee, at FERC and at its jurisdictional commissions. PJM has presented training programs and tutorials to members and interested parties.

- Beginning on December 8 and ending on December 10, 2008, ISO New England conducted the second New England Forward Capacity Market Auction for the Capacity Year beginning June 1, 2011 and ending May 31, 2012. ISO New England's Second Forward Capacity Auction Results Filing may be viewed at: http://www.iso-ne.com/regulatory/ferc/filings/2008/dec/index.html.

- PJM introduced a proposal for a Reliability Pricing Model ("RPM") in June 2004 and has subsequently presented and revised the proposal at numerous stakeholder meetings and has discussed the proposal with various PJM states PUCs. PJM has discussed the proposal with the NY PSC, with the NYISO and with MISO to ensure that the RPM proposal would not impact seams or create adverse impacts on regional markets. PJM filed its RPM proposal with FERC on August 31, 2005 and FERC held a technical conference on RPM on February 3, 2006. In an order on (Docket Numbers EL05-148-000, ER05-1410-000) April 20, the FERC endorsed the major principles of RPM. It called for the technical conference and hearings, which were held on June 7th and June 8th, to help resolve details prior to implementing RPM in place. RPM Settlement Proceedings were initiated in mid-June 2006. Parties filed proposed settlement on Sept 29, 2006 which is expected to be contested by a few parties in opposition. On December 21, 2006, FERC approved, with conditions, the RPM Settlement Agreement. The December 21st Order also denies rehearing of the Commission's finding of the April 20 order that PJM's current capacity market rules are not just and reasonable. PJM's first RPM auction began on April 2 and closed on April 6. It was for delivery of capacity during the 2007/2008 planning year (June 1, 2007 to May 31, 2008). The auctions procure needed capacity after participants have specified self-supply and contracted (bilateral) resources. Generally, annual auctions will procure capacity three years prior to the required need to provide opportunity for planned resources to compete to supply the needed capacity service. PJM's long-standing capacity requirement ensures that there are sufficient resources in place to meet the peak demand for electricity plus a reserve margin. PJM members can use generation, transmission or demand response, including energy-efficiency programs. They can meet their supply requirements by owning resources (self-supply) or contracting for them (bilaterals). PJM's analysis shows that the RPM will yield lower costs overall than the previous model. The intent of RPM is to send pricing signals that will attract investment in new capacity resources where they are most needed further enhancing reliability. The 2007-2008, 2008-2009, 2009-2010, 2010-2011 and 2011-2012 Base Residual Auction Reports and the 2008-2009 Third Incremental Auction Report are located on the PJM website under the corresponding Delivery Year headings: http://www.pjm.com/markets/rpm/operations.html.

- PJM commissioned a study in accordance with Open Access Transmission Tariff requirements to evaluate the performance of the Reliability Pricing Model in addressing the infrastructure investment issues identified by PJM and stakeholders in 2004-2006. The study report was released on June 30, 2008 and may be viewed at: http://www.pjm.com/documents/ferc/documents/2008/20080630-er05-1410-000.pdf.

- Following the issue of the Brattle Group Report on the Effectiveness of the Reliability Pricing Model in June 2008, PJM commissioned a stakeholder process to evaluate potential changes to the RPM market rules. Comprehensive proposals were created included changes to the RPM auction process design, the penalty structures, the types of resources that may participate, and the basis price that will factor into what the cleared resources will be paid (aka Cost of New Entry). None of the comprehensive proposals achieved super-majority in the stakeholder process. PJM subsequently filed with FERC to initiate a settlement process. The first meeting was held on December 16, 2008.

- The first RPM settlement meeting was held on December 16, 2008 in front of a FERC Administrative Law Judge. Settlement talks ended in January 2009, when parties established that agreement between them would not be possible. In February 2009, PJM filed with FERC a settlement agreement among some parties to resolve the issues at hand. PJM requested that FERC issue an order no later than March 27, 2009 so that changes could be implemented in time for the May 2009 RPM auction for the 2012/2013 Delivery Year.

- PJM has reconvened the Capacity Market Evolution Committee to address compliance items as directed in the March 26, 2009 FERC Order on the Reliability Pricing Model. The stakeholder group will investigate automated methods for updating the Cost of New Entry, which serves as the basis for price on the capacity market demand curve. The committee will also review the following issues: scarcity pricing revenue offset, incremental auction design, establishment of new Cost of New Entry regions, and longer-term issues. The FERC Order directs PJM to make compliance filings on September 1, 2009 and on December 1, 2009 to address various aspects of the capacity market design. (Q2-2009)

- Presentations were made by ISO-NE and PJM describing their FCM and RPM approved market designs at NYISO November 2nd and 17th, 2007 ICAP Working Group meetings.

- Further to the NYISO Board's direction, the NYISO presented to the ICAP Working Group, at meetings during 2008 and Q1 2009, an iterative design of a forward capacity market.

- The NYISO has engaged NERA to develop a conceptual forward market design.

- At the joint NYISO Board of Directors Management Committee meeting on June 10, 2008, and during several ICAP Working Group meetings in 2007, 2008, and Q1 2009, market participants expressed a range of views on the forward capacity market design proposed by the NYISO and two market participants presented alternate designs concepts.

- The present design presented by the NYISO for its stakeholders' consideration incorporates a voluntary forward capacity market for procurement of a portion of future resource requirement.
  The general design includes:

  Advance Auctions
  - Approximately 75 and 60 months prior to commitment year
  - Voluntary two sided auctions

  Forward Procurement (FP)
  - Certifications approximately 50 months prior to commitment year
  - FP approximately 44 months prior to commitment year
  - Primary purpose is for NYISO to ensure that capacity committed to market is adequate and regulated solution need not be triggered

  Reconfiguration Auctions
  - Physical Reconfiguration Auction - covers load forecast changes, replacement of FP capacity failing to meet milestones - held at y-37 months, y-23 months and y-10 months and accelerated if there was a significant failure of qualified capacity
  - Voluntary Reconfiguration Auction - to allow reconfiguration of positions taken in the voluntary auctions (e.g., marketers)

  Strip Auction (conceptually unchanged from current design)
  - Annual auction held before spot auctions

  Spot Auction (conceptually unchanged, frequency may be reduced from monthly to less frequent)
  - Would use Demand Curve

- Work on remaining design elements is continuing in Q1 and will continue is Q2 2009.

- In Q1 2009, the NYISO engaged The Brattle Group to conduct a comparison of the costs and benefits of the contemplated forward capacity market design to the NYISO existing capacity market. The Brattle

Group's analysis will include information received during stakeholder sector focus group meetings it will conduct in April 2009. The Brattle Group's draft report will be presented at the NYISO's ICAP Working Group meeting on May 8, 2009, and the final report will be presented at the June 5, 2009 ICAP Working Group meeting.

- The NYISO plans to present a forward capacity market proposal to the Business Issues Committee for vote. The outcome of that vote will determine the degree to which resources are committed to fully develop FCM market rules and tariff language.

- At the March 19, 2009 ICAP Working Group meeting, the NYISO presented details on qualifications and milestones for new entry to participate in a forward procurement auction, In-City mitigation, credit requirements, settlement rules and seasonal variations issues associated with the forward capacity market design proposal, and revisions to the demand curve setting process.

- The Brattle Group presented the cost benefit evaluation report for replacement of the NYISO's existing Installed Capacity (ICAP) market with a new Forward Capacity Market (FCM) to the ICAP Working Group meeting on June 5, 2009. The evaluation report was based on three key inputs; stakeholder comments from sector focus group meetings, the PJM and ISO-NE experience with FCM development, and economic theory and literature relevant to forward capacity markets. The report concludes that a mandatory forward capacity market could have greater long-term net benefits than the existing ICAP market. However, the incremental benefits would not be reaped until new capacity is needed. The NYISO's most recent Reliability Needs Assessment (RNA) base case projects capacity surpluses through 2018. Monitoring both the PJM and ISO-NE experience with their forward market design would provide additional experience to guide the development of a FCM for NYISO. Deferring the development of an FCM market design would allow the NYISO to allocate resources to other high priority capacity market enhancements. (Q2-2009)

- At the June 10, 2009 NYISO Business Issues Committee Meeting (BIC) meeting the NYISO conducted an advisory vote to ascertain Market Participant interest in further development of functional requirements for an FCM. A majority of NYISO Market Participants supported ending the current FCM development work. The NYISO will continue to monitor the progress of neighboring forward capacity market designs. (Q2-2009)

- This project has been moved to the closed list. PJM, ISO-NE and NYISO all have capacity markets in place that provide for cross border capacity sales. The Regional Resource Adequacy Working Group is no longer active. (Q3-2009)

P18 NYISO AND ISO-NE – INTRA-HOUR TRANSACTION SCHEDULING (ITS) (INCLUDING PARTICIPANT DRIVEN AS WELL AS VIRTUAL REGIONAL DISPATCH (VRD) SOLUTIONS)

ITS is intended to provide a means to respond to excessive and persistent price differentials between the markets at times when sufficient capacity remains available on the transmission interface to provide substantive reduction in the differential. Due to market rules associated with transaction scheduling that require over one hour of advance notice to schedule a transaction and the associated risks to market participants, price differences are not well arbitraged in real-time by Market Participants (MPs).

- NYISO and ISO-NE have documented a technical definition of a virtual regional dispatch process and have received potentially viable alternative methodologies from their stakeholders. The ISOs will proceed with further stakeholder meetings to finalize the technical definition and to work towards a joint stakeholder acceptance of the proposal.

- The first set of pilot tests were conducted on April 20-21, 2005. Any additional tests will be scheduled based upon results evaluation of the April tests.

- NYISO and ISO-NE issued a report on the first pilot test on October 24, 2005. A joint meeting of NY and NE stakeholders to review the pilot test report and further develop market participant based proposals for improving the efficiency of the NYISO/ISO-NE interface was held on November 14, 2005. Based on discussions at that meeting, ITS will be considered along with other market issues as part of the NYISO rules assessment initiative currently underway.

- Prior to the interruption in ITS activity a participant-initiated proposal for intra-hour transaction scheduling was under consideration. (http://www.nyiso.com/public/committees/documents.jsp?com=bic_mswg&directory=2005-01-18&cols=5&rows=5&start=26&maxDisplay=999). The proposal would allow transactions to be scheduled on shorter notice and, potentially, for shorter duration. The shorter timeframes would allow participants to more quickly respond to price differences between the two areas.

- In 2007 NYISO evaluated inter-market real-time transaction scheduling as part of an evaluation of scheduling and dispatch market rules. http://www.nyiso.com/public/committees/documents.jsp?com=bic_miwg&directory=2007-05-24&cols=5&rows=5&start=1&maxDisplay=999. A resumption of ITS efforts would then consider any potential changes recommended by the NY rules assessment. Both NYISO and ISO-NE have high priority, large projects underway that preclude activity on Intra-hour Transaction Scheduling before 2008.

- NYISO and ISO-NE will jointly perform an analysis of the impact of uneconomic interchange between the NYISO and ISO-NE control areas. This analysis will attempt to identify the potential economic benefits of more efficient use of available interface transfer capacity. The ISO's intend to bring the results of this analysis forward to stakeholders for review and feedback. NYISO and ISO-NE will work together to identify market mechanisms that can lead to more efficient scheduling and dispatch across the interface between control areas.

- On June 23, 2008, the NEPOOL Participants Committee voted to support an ISO-NE proposal to allow intra-hour scheduling of transactions with neighboring control areas. Rule revisions to implement this change will be filed with the FERC in July 2008. Initially ISO-NE expects to implement this scheduling functionality at the New Brunswick interface. These rule revisions were approved by the FERC on September 30, 2008 (Docket # ER08-1277-000) to be effective on October 1, 2008.

- The NYISO's 2007 State of the Market Report provides an analysis of scheduling and pricing patterns at the NYISO's interfaces with neighboring control areas. This analysis indicates that there is an opportunity to increase the efficient use of transfer capacity during unconstrained periods resulting in both production cost and net consumer benefits in both control areas. The analysis indicates that reducing the transaction scheduling lead time would enable market participants to more efficiently schedule transactions. The report recommends the development of processes to improve coordination between the ISOs even if only during limited circumstances, such as reserve shortages.

- On October 10, 2008, the NYISO presented a proposal for a reserve shortage protocol. The protocol would allow for the curtailment of RTC export transactions to maintain adequate reliability based Operating Reserves due to unforeseen events until normal market transaction scheduling has an opportunity to solve for these events. The NYISO is in the process of developing revisions to its Operational protocols to accommodate this process. The NYISO intends to present additional details and responses to questions at stakeholder meetings in early 2009.

- The NYISO reviewed the Reserve Shortage Operating Protocol proposal with market participants at the January 5, 2009 Market Issues Working Group and the January 20, 2009 System Operations Advisory Subcommittee meetings. The protocol was also discussed at the February 20, 2009 Market Issues Working Group meeting. Revisions to operating procedures and training materials are under development. Implementation of the protocol is expected in the second quarter of 2009. The NYISO also met with ISO-NE operational staff to review the proposed changes.

- On June 1, 2009 the NYISO implemented a new operating protocol for handling RTC export transactions to ISO-NE during times of reserve shortages. The reserve shortage operating protocol states that if a deficiency of 10 minute Operating Reserves (East 10 and NYCA 10) occurs, or is forecasted to occur, for a sustained period, as a result of an unforeseen event, the NYISO may curtail RTC scheduled export transactions to ensure adequate reserves are available to meet requirements. ISO-NE already has an operating protocol in place to address reserve shortages through curtailment of export transactions. Specific details of this protocol were discussed with Market Participants at the NYISO's Market Issues Working Group (MIWG) meetings and in the System Operations Advisory Subcommittee (SOAS) meetings on May 6, 2009 and May 20, 2009 respectively. On June 23, 2009 a draft Technical Bulletin, #187-Reserve Shortage Operating Protocol was posted to the NYISO website and distributed to Market Participants for review and comment. (Q2-2009)

- The NYISO is assessing the feasibility of a project to enhance interregional transaction coordination by offering dynamic transaction scheduling capabilities at the NYISO borders. This concept would provide Market Participants with the ability to submit flexible transaction schedules for evaluation on an intra-hour basis. Development of this capability is initially targeted for the HQ interface with the roll-out to additional interfaces in future phases. Future phases of the project may provide for the sale of reserve and regulation products; however, this functionality is not within scope of the current design effort. At the June 26, 2009 Market Issues Working Group (MIWG) the NYISO presented an overview of this concept. (Q2-2009)

- This project has been moved to the closed list. A new project, P37 *Enhanced Interregional Transaction Coordination*, has been added to the report. This project will cover efforts to improve the coordination of energy scheduling at the borders between control areas. (Q3-2009)

P21 NORTHEAST GENERATOR ATTRIBUTES TRACKING (GAT) SYSTEM

Green power suppliers need transparent and efficient tracking of the attributes of green power traded across the ISOs that assures that no double counting occurs.

- NY is working with market participants to determine the suitability of adapting the New England Generator Information System (GIS) to New York markets. The NYISO has been actively participating in the NY Dept. of Public Service hearings on a Renewable Portfolio Standard, where attributes trading is identified as a necessary and desirable condition. On September 24, 2004, the New York State Public Service Commission (PSC) issued its Order on the Renewable Portfolio Standard that outlines a centralized procurement process for renewables. A workshop on the need for a GATS system, sponsored by the PSC and New York State Energy Research and Development Authority (NYSERDA), was held on July 14, 2005. On September 21, 2005, the PSC issued a State Administrative Procedure Act (SAPA) notice stating that it is considering authorizing PSC Staff and NYSERDA, in consultation with the NYISO, to begin the design of a certificate-based tracking and trading system. In the RPS Program January 26, 2006 Order in Case 03-E-0188, the New York Public Service Commission expressed its inclination to modify the current Environmental Disclosure Program to include an attributes accounting system similar to systems used in other states. The NYISO, NYPSC, and NYSERDA met on December 19, 2006 to discuss the PSC's implementation schedule and to review the potential involvement of the NYISO in such a system.

- NYISO is supporting the NYSERDA and NYDPS staff effort to develop a comprehensive set of functional requirements for a New York GATS. (Q2-2009)

- The IESO is awaiting direction from government before proceeding further on this initiative.

- PJM Environmental Information Services Inc (PJM-EIS), a wholly owned subsidiary of PJM Technologies, launched its Generation Attribute Tracking System (GATS). The system was placed in service in September 2005. The system is now being used by PJM LSEs to demonstrate compliance with RPS programs in five PJM jurisdictions (NJ, MD, DC, DE, and PA). As of March 2008 there are 181 subscribers and 342 registered renewable generators in GATS. 22 of these registered renewable generators are located outside of PJM in regions where a tracking system does not currently exist. Each of these external facilities has qualified for one or more PJM-state RPS programs, and GATS facilitates their participation and enhances their liquidity.

- In July 2002, the New England Power Pool (NEPOOL) launched the NEPOOL Generation Information System (GIS). This system tracks the generation attributes, emissions, and outputs of all generators in New England. The system also facilitates the trading of renewable energy certificates (REC) for states with renewable energy portfolio standards (RPS). Consistent with current New England state requirements, NEPOOL's Generator Information System Operating Rules recognize the need to track the attributes of all energy transmitted between New England and other ISOs. Under those rules, energy transactions with unit-specific NERC Tags are given the attributes of the particular generating station while all other energy transactions are given attributes of the system mix of the exporting control area.

- The NEPOOL GIS was the first tracking system in the nation to support multi-state RPS programs. The PJM-EIS GATS was designed on the basis of the NEPOOL GIS. Although there are some functional differences, the two systems are compatible in architecture, core functionality and look-and-feel.

P24 CROSS-BORDER CONTROLLABLE LINE SCHEDULING

NYISO software will be designed or modified to model Controllable Lines across control areas through an external proxy bus, providing market participants with the ability to bid to or from the new proxy bus in the Day-Ahead Market and schedule transactions in real-time. NYISO and ISO-NE operators will have the ability to monitor a Controllable Line and curtail transactions on the line.

- Full market deployment of the Cross-Sound Scheduled Line occurred on June 7, 2005.. The Northport-Norwalk Scheduled Line was implemented on June 27, 2007. The Neptune Scheduled Line was implemented on July 1, 2007. The Dennison Scheduled Line was implemented in the NYISO’s markets on October 1, 2008.

- Linden VFT, a 300MW injection from PJM to NYISO is targeted to begin operations during the third quarter 2009 with full operation targeted for the fourth quarter of 2009.

- Details on the operation, transmission reservations, and Tariff changes to support implementation of the Linden VFT Scheduled Line in the New York energy market were presented at the NYISO’s MIWG teleconferences on January 26 and 30, 2009.Tariff changes necessary to support implementation of the Linden VFT in the energy market were passed at the NYISO’s February 25, 2009 Management Committee meeting , were approved by the NYISO Board on March 17th and will be filed with FERC. NYISO will work with PJM and Con Ed to ensure emergency operating protocols are in place prior to operation of the Linden VFT Scheduled Line.

- The NYISO Tariff changes to support the implementation of the Linden VFT in the NYISO energy markets were approved by FERC on May 27, 2009. (Q2-2009)

- Test flows of power on the Linden VFT began on September 16, 2009. Commercial operation is targeted to begin on November 1, 2009. The NYISO will provide notice to FERC and to its Market Participants at least two weeks prior to commencing commercial operation over the Linden VFT Scheduled Line. (Q3-2009)

P33 INTERREGIONAL CONGESTION MANAGEMENT

NYISO and PJM are evaluating a coordinated bilateral Congestion Management Process concept. PJM and NYISO met in April and May 2007 and discussed possible opportunities for coordination. The main intent of this activity is to develop a concept that enables optimal dispatch between control areas such that one control area may alleviate congestion in the other.

- A straw-man proposal is planned to be developed by late 2007 with market participant review planned for early 2008. Any PJM-NYISO congestion management results are expected to be shared with ISO-NE. PJM and NYISO met in September 2007 to continue discussion of possible opportunities for coordination.

- NYISO and PJM are evaluating a coordinated bilateral Congestion Management Process concept. The intent of this activity is to develop a concept that enables optimal dispatch between control areas such that one control area may alleviate congestion in the other. NYISO continues to work with PJM on the development of a feasible process. NYISO presented a Congestion Management process overview to market participants at the December 14, 2007 Market Issues Working Group.

- PJM and NYISO had a productive meeting on January 29th, 2008 to continue discussions on a potential congestion management process. More specifically, the parties reviewed RTO to RTO redispatch examples, interaction between any new process and existing PJM NYISO agreements and potential data exchanges. It is PJM's and NYISO's intent to complete the development of a conceptual design for a congestion management process and present this to stakeholders by the end of 2008.

- PJM and NYISO have held several meetings in the first half of 2008 to develop a conceptual design for implementing a coordinated congestion management process. These discussions have focused on the overall design, potential operational procedures and data coordination protocols necessary to integrate a congestion management process. The last meeting between the design teams occurred on April 9th, 2008. The ISOs will continue work on the development of a conceptual design serving the needs of both control areas with the intent of bringing a proposal forward by the end of 2008.

- The Commission issued an order November 17, 2008, approving NYISO's exigent circumstances/loop flow tariff filing in Docket No. ER09-198-001. In this order, the Commission directs NYISO to work with its market participants, NERC, and neighboring RTOs to develop potential solutions to the loop-flow problem on a comprehensive basis through a collaborative process. The Commission also directs the NYISO, within 90 days of the date of the order, to file a status report on its progress in developing solutions to the loop flow problem, including an inter-RTO congestion management process. NYISO and PJM staff met on December 12, 2008 to continue discussions on a congestion management process.

- On February 12, 2009, NYISO hosted a technical conference for market participants, with representatives from PJM, MISO, IESO and ISO-NE participating, to discuss design considerations and take stakeholder feedback on the development of an Interregional Congestion Management Process. NYISO and PJM staffs have met to discuss the details of performing the market flow calculation and have begun the internal evaluation of identifying the necessary data to be shared to support that process.The NYISO's 90 Day Status Report on Development of Solutions to Loop Flow and Development of Inter-ISO/RTO Congestion Management Process was filed on February 17, 2009.

- PJM and NYISO continue to work on the development of a market flow calculation tool. The development of a unified approach to the calculation of market flows across regions is required in order to evaluate the implications of the use of historic entitlements in a congestion management process. The NYISO presented an overview of activities in support of the development of a congestion management process at the June 26, 2009 Market Issues Working Group (MIWG) meeting. (Q2-2009)

- At the September 1, 2009 Market Issues Working Group (MIWG) meeting, the NYISO provided an update on efforts to develop a congestion management process. The current effort is focused on development of the market flow calculation tool and identification of the appropriate baseline for measuring relief provided as part of the settlement process. As noted in the presentation, the plan calls for implementation of the market flow calculation tool in 2010 with full implementation of a congestion management process between NYISO and PJM in 2011 and implementation with additional neighboring control areas in 2013. Also included in this presentation is a schedule for the development of these proposals to support a January 2010 filing with FERC. The presentation can be found at http://www.nyiso.com/public/webdocs/committees/bic_miwg/meeting_materials/2009-09-01/MIWG_Market_Solutions_to_Loop_Flow.pdf. (Q3-2009)

P36 LONG-TERM SOLUTION FOR UNSCHEDULED LAKE ERIE LOOP FLOWS

Unscheduled power flows, particularly around Lake Erie, can negatively impact both electric system reliability and market operations. The NYISO is conducting a comprehensive investigation of transaction scheduling and pricing protocols and incentives in order to assist its efforts to work with PJM, MISO and IESO to develop an alternative long-term solution to mitigate the market and reliability impacts of unscheduled Lake Erie power flows. The results of this ongoing analysis have been, and will continue to be, shared with stakeholders to facilitate an informed discussion of a viable long term solution for managing loop flow.

- Representatives from NYISO, PJM, IESO and MISO met on March 23, 2009 to address the development of solutions to mitigate loop flows. Discussion of the underlying causes of loop flow and the process for sharing data to further the analysis were discussed.

- NYISO met with PJM in June 2009 to discuss their experience with a process that allows MPs to "buy through" TLRs. The NYISO is exploring this process as a potential solution to manage loop flows on a long term basis. The NYISO expects to provide an update on the development of a solution to address loop flow at a future Market Issues Working Group (MIWG) meeting. (Q2-2009)

- The NYISO is working on the development of a "buy-through of congestion" approach to manage the cost of loop flows. This would require a collective solution among all of the ISO and RTO markets surrounding Lake Erie to manage scheduling data and settlement impacts, firm transmission and the potential for free-riders. This approach would entail charging parties scheduling transactions for the cost of congestion incurred by neighboring systems to support flows on systems that are not part of the direct scheduling path for the transaction. A presentation providing additional details on this approach can be found at http://www.nyiso.com/public/webdocs/committees/bic_miwg/meeting_materials/2009-09-01/MIWG_Market_Solutions_to_Loop_Flow.pdf. (Q3-2009)

- FERC's July 16, 2009 Lake Erie Report/Order orders the NYISO to "expeditiously develop long-term comprehensive solutions to the loop flow problem with its neighboring RTOs, including addressing interface pricing and congestion management. NYISO is required to submit a compliance filing to FERC detailing its proposed solution, including necessary Tariff revisions by mid-January 2010. Executives from PJM and the NYISO met on August 12, 2009 to address the July 16, 2009 FERC order, physical solutions and market solutions to address circuitous transaction schedules. (Q3-2009)

- On September 16, 2009, FERC issued an Order Granting Clarification to the NYISO request for clarification or rehearing of the Commission's order issues July 16, 2009. In this Order, FERC states "we clarify here that NYISO must address, in its 180-day report, all solutions to the Lake Erie loop flow problem, including but not limited to: (i) the implementation status of the Ontario-Michigan PARs; (ii) the progress that has been made on the operating agreements for the Ontario-Michigan PARs; and, (iii) the complementary role that physical controls will play in the comprehensive solution to the Lake Erie loop flow problem." (Q3-2009)

- Representatives from Midwest ISO, NYISO, IESO and PJM have conducted a series of conference calls on August 27, September 3 and September 10 followed by an in-person meeting on September 14 to discuss the development of solutions to mitigate loop flows around Lake Erie. These conference calls discussed the implementation status of the Ontario-Michigan PARS, improvements to the process for sharing data to support further loop flow analysis, and solutions to support the development of broader regional markets. (Q3-2009)

- A white paper addressing the development of broader regional markets is being written. The white paper will address solutions to loop flows (both physical and market based,) congestion management and interregional transaction coordination. This white paper is expected to be the focal point of discussion for a joint ISO-stakeholder meeting scheduled for October 29, 2009 in Albany, New York. (Q3-2009)

P37 ENHANCED INTERREGIONAL TRANSACTION COORDINATION

The NYISO is leading an effort to develop enhanced interregional transaction capabilities at its borders with neighboring control areas. This enhancement would allow market participants to submit flexible transaction bids for evaluation on an intra-hour basis leading to sub-hourly adjustment of transaction schedules and interchange between control areas. This capability would support convergence of scheduled interchange with pricing patterns between control areas. It would also expand the pool of flexible resources available to balance intermittent generation between control areas and improve transmission utilization and price consistency between control areas. Implementation would take place in phases in conjunction with neighboring control areas.

- At the September 1, 2009 Market Issues Working Group (MIWG) meeting, NYISO provided an overview of the enhanced interregional transaction scheduling capability. The presentation can be found at: http://www.nyiso.com/public/webdocs/committees/bic_miwg/meeting_materials/2009-09-01/Enhanced_Interregional_Transaction_Coordination_Concept.pdf. This presentation includes an overview of energy bidding, scheduling, pricing, settlement and NERC tag changes necessary for the initial phase of this project supporting intra-hour energy transactions at the NYISO-HQ interface and additional details regarding the schedule for further review with stakeholders. (Q3-2009)

I4 REDUCED LEAD TIME FOR IN-DAY TRANSACTION SCHEDULING (NY)

NYISO market participants have expressed a desire to reduce the lead time for submission of real time transactions below the 75-minute limit currently in effect. This feature will also be considered as part of the NYISO rules assessment initiative currently underway. (July 2003)

- At the March 20, 2009 Market Issues Working Group the NYISO presented an overview of the current 75-minute bid lockdown. Scheduling of transaction for the next hour and 30-minute gas turbine commitments are the primary reason for this timetable. Some market participants have speculated that reducing this window would permit less expensive resources to be scheduled, however, NYISO is not aware of any changes in costs for resources that are unable to be represented prior to the 75 minute bid lockdown. As the NYISO currently evaluates every 15 minutes for the least cost solution, the NYISO sees no demonstrable benefits of reducing the bid lockdown. Subsequently, NYISO does not endorse reducing the current 75-minute window due to potential negative impacts resulting from a less secure bid set.

I6 RESERVES PARTICIPATION IN ADJACENT REGIONAL MARKETS (NY–NE-HQ)

There is Market Participant interest in selling operating reserves from generation sources in one region to provide reserves in another region. This issue will be considered along with other longer-term market issues as part of the NYISO Market Evolution Plan, which was presented to NY stakeholders in June 2005. Since late 2005, the NYISO's Market Evolution Plan is part of its strategic planning process. The NYISO suggested this item to its Market Issues WG for stakeholder discussion and prioritization. Following implementation (October 2006) and assessment of their reserve market, ISO-NE will consider inter-control area provision of reserves. (April 2004).

- Reliability issues related to inter-area reserve have been addressed at the NPCC level, and concepts have been approved to be placed in NPCC Criteria documents.

- Two alternatives were explored. One was an expansion of existing ISO-NE/NYISO reserve sharing agreements, which was rejected because it would meet reliability interests but not market interests. The second alternative was preferred in that it would give access to external reserve resources to the ISO-NE and NYISO markets and would allow competition for the provision of reserve reliably and on a comparable basis.

- ISO-NE and NYISO have had preliminary implementation discussions, but the effort is presently on hold due to manpower limitations and awaits prioritization for implementation. ISO-NE's ability to aggressively pursue this initiative is very much dependent on the final schedules for completion of major market initiatives currently under way or pending FERC decisions and on the results of the collaborative priority setting process that ISO-NE conducts with its stakeholders.

I7 THE IMPACT OF EXTERNAL TRANSMISSION OUTAGES ON CONGESTION RENT SHORTFALLS AND ICAP MARKETS (NY-NE**)**

In the TCC auctions that it conducts, the NYISO permits bidders for TCCs to specify external proxy generator buses as the injection or withdrawal locations. Transmission outages or deratings occurring outside of the NYCA that are not anticipated at the time of a TCC auction can force the NYISO to reduce the assumed transfer capability between the NYCA and the adjacent control area. If the resulting set of TCCs is rendered infeasible, the NYISO will incur congestion rent shortfalls in the day-ahead market. There is currently no way to assign the cost impact (due to the congestion rent shortfall) of that outage to the responsible external transmission owner. TCCs in New York are fully funded, therefore the New York Transmission Owners are exposed to revenue shortfalls when transfer capability is reduced by external outages outside of their control. In addition, transmission outages or deratings that cause reductions in transfer capability between regions may have an impact on ICAP sales between regions. Due to the emphasis on evaluating SMD2 performance subsequent to deployment in February 2005, NY deferred stakeholder discussion on this issue. NYISO Senior Management will evaluate project, scheduling, and budget impacts in conjunction with all other identified initiatives and determine what further action will be taken. (Oct 2004)

I8 ELIMINATION OF RATE PANCAKING

The NYISO, with the support of the New York TOs, will initiate discussions among the affected parties in the Northeast to explore the potential for rate pancaking relief between New York and PJM. A meeting between the NY and PJM TOs was held on August 18, 2005 to initiate discussions on this issue. With the Transmissions Owners as the primary drivers of this issue, NYISO and PJM are awaiting indications of intent from PJM's TOs as to the level of priority this issue has with the PJM's TOs. On November 02, 2006, PJM supplied transaction data regarding volume and rates for PJM exports into NY.

- The NYISO has also initiated discussions with IESO to eliminate export fees. The revenue application review process for the transmitter that owns the inter-tie transmission lines in Ontario, and is responsible to the provincial regulator for this fee, is currently ongoing. The possibility of eliminating the transmission export fee, along with other options, is being discussed at this rate hearing. In May 2007, the Ontario Energy Board recently upheld the $1/MWh export charge from IESO. However, the IESO will be (1) conducting a study on appropriate export transmission service rates for Hydro One Networks' 2010 rate process; and (2) will start negotiations with the NYISO and other neighboring jurisdictions to pursue reciprocal arrangements to eliminate export charges. The IESO will begin discussions with its neighbors early in 2008 and will complete its market impact studies in 2009. The Ontario Energy Board must approve any changes to Hydro One's export transmission charges.

I14 Asymmetric Capability Year Impact on Inter-Area Capacity Sales

The NYISO capability year begins May 1st, while the capability years for both PJM and ISO-NE begin on June 1st. The election to use Unforced Deliverability Rights (UDRs) for controllable tie-line capacity at an interface with an external control area is factored into the NYISO's annual planning process determining locational capacity requirements. The capacity of a controllable tie-line not used for UDRs may be modeled as emergency assistance in the planning process, subsequently reducing the locational capacity requirement. The one month difference between capability years across the ISOs may be an issue in instances where full capability year obligations or contracted capacity from one control area is transitioned meet requirements in the neighboring control area.

- NYISO and LIPA are discussing potential ways to address the impact for the May 2010 period.

- The NYISO is evaluating a number of options associated with the May/June difference; any option will likely involve changes to NYISO tariffs, manuals, and possibly New York State Reliability Council (NYSRC) rules. The NYISO expects to provide a proposal to MPs in the near future. (Q2-2009)

- NYISO has included a project to consider the extent of market rule changes, software changes and potential operations procedure changes that would be required to align NY's capability year with those of PJM and ISO-NE in its 2010 project candidate list including a recommendation to pursue this initiative. (Q3-2009)

Broader Regional Planning

P26 COORDINATION OF INTERREGIONAL PLANNING

To continue to develop ways to improve the coordination of planning for the Northeast region, this project is established to identify future deliverables towards achieving progress in this endeavor. ISO-NE, NYISO and PJM will be presenting the results of their current efforts under the Northeastern Coordination of Planning Protocol. Under the Northeastern Coordination of Planning Protocol, a Northeast group of NYISO, PJM, & ISO-NE called "Joint ISO/RTO Planning Committee" (JIPC) met with market participants at the March 23, 2007 meeting of the Inter-area Planning Stakeholder Committee (IPSAC) and several presentations were made. PJM, NYISO, and ISO-NE are currently exchanging modeling information and load flow analysis such that work completed in 2006 can be expanded in the 2007 work-plan.

- On December 14, 2007 another IPSAC meeting was held by teleconference and web-ex at which the ISOs made presentations on several topics, including: New England Loss of Source Feasibility Study; planned system improvements in each ISO/RTO region; environmental and renewable resource issues. In addition, the ISOs presented their proposed Scope of Work for an inter-regional transmission adequacy study for discussion and stakeholder input. Stakeholders raised additional issues that are currently under consideration. Interim study results for the transmission analysis were discussed with stakeholders at an IPSAC meeting held on June 27, 2008. At this meeting, the ISO/RTOs also reviewed their plans for additional analyses with stakeholders. Plans call for conduct of further transmission studies, and production analyses. An update will be presented to stakeholders at a meeting planned for the 4th quarter 2008.The agenda and meeting materials from the Dec 14, 2007 and the June 27, 2008 meetings are posted at the following link: http://www.interiso.com/documents.cfm. Additional materials have been posted by each of the ISO/RTOs on their secure links.

- The integration of over 450 MW (nameplate) of wind resources in the NY North Country is planned for 2009. ISO-NE and NYISO are conducting joint operating studies to ensure reliable operation of the system. These issues were discussed with stakeholders at the June IPSAC meeting.

- During the month of August 2008, high-level meetings were held between NYISO, PJM and ISO-NE to discuss possible expansion of inter-regional planning activities. Follow-up meetings were held.

- An IPSAC meeting was held on December 11, 2008 at which the following items were discussed: the NCSP, the Joint Coordinated System Plan, the North – Country Vermont Study, PJM 500kV Expansion Studies; Environmental Issues, Interregional Wind Integration Issues and Next Steps. Additional presentations demonstrated that Queue studies and other studies have also been well coordinated and resulted in proactive system plans.

- The draft NCSP was posted on January 9, 2009 and an IPSAC conference call was held on January 30, 2009 to discuss comments on the draft Plan and to receive further input from stakeholders regarding continuing studies of interregional system assessments and system improvements.

- Following these two IPSAC meetings a final comment period was concluded on February 4 and the final NCSP was posted on March 3, 2009. The final NCSP is a comprehensive document that discusses: summaries of the RTO's system plans, interregional studies conducted by the JCSP that include the coordination of projects in the Queues having potential interregional impacts, additional coordinated planning activities and issues, wind and renewable resource studies, key environmental issues with potential interregional impacts, renewable resource development, demand side resource development, and plans for additional JIPC analysis.

- Next steps planned are summarized in the NCSP. In particular, NYISO and PJM will be conducting both reliability and production cost analyses which will focus on the New Jersey – Southeast New York area. In addition new tie lines are being explored, including further analysis between ISO-NE and NYISO, as well as their respective transmission owners, that builds upon the prefeasibility study of a tie between Plattsburgh and Vermont. Upon completion of these studies, plans call for conducting a feasibility analysis of the need for a new tie between southern New England and Southeast New York.

- An IPSAC WebEx was held May 7, 2009 to discuss the planned scopes of work and the status of study work. Preliminary results of the Vermont-New York interconnection studies and the NYISO/PJM focused study reliability analysis were presented to stakeholders at an IPSAC meeting held on June 30, 2009. Other topics presented at this meeting included an overview of other inter-regional planning activities, coordination of studies and databases, an overview of each ISO's economic planning process and plans for development of an inter-regional production costing database for future economic analysis. Economic analysis will include focused studies of the ability to transfer power across the New York - PJM interface. Additional economic analysis will focus on the ability to transfer power across the New York - New England Interface. Once the coordinated data base is fully developed, plans call for conducting economic analysis for the three ISO/RTO regions. (Q3-2009)

- An IPSAC meeting was held on June 30, 2009 when an update was provided on: the Vermont-New York New Interconnection; North Country Studies including the integration of wind resources; NYISO/PJM Focused Reliability Study that will confirm generator deliverability modeling used in resource adequacy studies; Other Interregional Planning Activities such as the planned formation of the Eastern Interconnection Planning Collaborative (EIPC); Coordination of Studies and Databases Overview of ISO Economic Planning Processes for ISO-NE; NYISO, and PJM; and Background on joint modeling and plans for joint Interregional Economic Planning Efforts. (Q3-2009)

- An IPSAC WebEx meeting is scheduled for November 6, 2009. The WebEx will provide a status update regarding analysis of the Vermont-New York New Interconnection, NYISO/PJM Reliability and Market Efficiency Analysis and the development of a common economic database for the combined region. Process improvements for coordinating interconnection studies and transmission planning studies are under development. An in-person IPSAC meeting is being planned for mid-December in New England. (Q3-2009)

P34 LIMITATIONS DUE TO LOSS OF LARGE SOURCE

ISO-NE has historically limited resources above certain MW levels when tripping at higher outputs could result in reliability problems for one of the other northeastern markets. PJM, NYISO and ISO-NE have filed a joint protocol with FERC on the coordination of loss of source procedures (http://www.iso-ne.com/regulatory/ferc/filings/2006/dec/er07-231-000_12-22-06_iso_phase_ii.pdf). On January 12, 2007, the Commission issued an order in docket no. ER07-231-000 accepting the joint protocol, without suspension after 60 days notice, effective January 16, 2007. The Commission found, however, that it should have been filed under Section 205 of the FPA and directed the RTOs/ISOs to resubmit the Protocol on tariff sheets. The RTOs/ISOs complied with this directive on February 12, 2007. On May 21, 2007, the Commission issued an order accepting the tariff sheet revisions for the Phase II Procedure, with an effective date of January 16, 2007.

- Operating studies of the loss of source, including the Phase II HVDC line connecting Quebec and New England, have been updated and approved. Planning studies simulating loss of source events have been updated. The results of these studies were reviewed at the March 23rd Inter-Area Planning Stakeholder Advisory Committee meeting.

- Analysis of potential of short-term transmission changes (series reactors) that could relieve the severity of the loss of source contingencies have been shown to produce marginal benefits and to introduce potential operating problems. They were discussed at the December 14, 2007 stakeholder meeting and it was agreed that these changes should not be pursued.

- Draft results of a long term assessment of the transmission system that reflects major improvements planned for NYISO, PJM, and ISO-NE were presented at the June 27, 2008 IPSAC meeting.. This assessment includes a determination as to their effect on the limitations on the size of allowable source loss in New England. The analysis also identifies the technical feasibility of mitigating the loss-of-source through the use of voluntary load shedding. Compatibility of such a mechanism with existing reliability rules must also be determined. The preliminary results suggest that the loss of source limit could potentially increase to a 1,500 MW to 1,600 MW level by the 2012 timeframe. A pre-feasibility study that determines the impacts of upgrading the Plattsburgh-Vermont tie to 230kV and of adding a 345kV tie between Southwest Connecticut and Westchester was also discussed with stakeholders. These improvements could result in a further increase in the loss of source limit. Additional study results will be discussed at an IPSAC meeting planned for the 4th quarter 2008. As needed, further analysis will then identify and analyze representative system improvements for discussion with stakeholders in 2009.

- Current plans call for presentation of more detailed study results at the December 2008 IPSAC meeting. These will more fully evaluate the impacts of 500kV transmission improvements in PJM and a potential upgrade of the Plattsburgh-Vermont tie.

- A status of more detailed loss of source studies was presented at the December 11, 2008 IPSAC meeting. With the addition of the planned 500kV improvements by 2012, the loss of source limit will likely be constrained by limitations in the PJM system to the 1,500 MW level. At 1,600 MW, the New York constraint will become less binding than the PJM constraint at that time. Loss of source analysis is continuing as a part of other interregional studies, such as the NY-VT tie, and the NJ- Southeast NY studies referenced in P26. The loss of source issues and studies are summarized in the NCSP and will be included in ongoing JIPC analysis reported under P26. This item as separate and distinct is considered closed. (Q3-2009)

P35 Eastern Interconnection Planning Collaborative (EIPC)

On September 1, 2009, 23 planning authorities representing about 95% of the peak load in the Eastern Interconnection, entered into an agreement to form the Eastern Interconnection Planning Collaborative Analysis Team. The goal of this initiative, the first of its kind in the Eastern Interconnection, is to provide a grass roots approach to interconnection-wide transmission analysis by the roll-up of the existing regional plans to identify potential opportunities for efficiencies between regions.

On September 14, 2009, members of the EIPC submitted a proposal, in response to a DOE Funding Opportunity Announcement, for performing interconnection-wide transmission analyses. The project proposes to facilitate the establishment of a multi-constituency stakeholder steering committee to provide strategic guidance to the technical studies. It is anticipated that this initiative will provide benefit to states, policy makers and other stakeholders by providing a coordinated analysis of scenarios of interest and developing potential transmission expansion options and cost estimates to inform their decisions. The DOE anticipates making an initial award selection in early November and a final award by the end of the year.

- The EIPC has announced two Webinars for October 13th and 16th to initiate dialogue with stakeholders, to receive input and to answer questions regarding this initiative. (Q3-2009)

I13 INTERREGIONAL COST ALLOCATION

The Northeastern ISO/RTO Coordination of Planning Protocol currently provides that cost allocation will be addressed consistent with the provisions of each ISO/RTO's Tariff. The discussions between NYISO and PJM and between NYISO and ISO-NE referred to in item P26 above also included potential consideration of a cross-border cost allocation mechanism for prospective application.

- At the December 11, 2008 IPSAC meeting there was discussion of interregional cost allocation. The ISO/RTOs current plans call for an open stakeholder process to address interregional cost allocation once projects have been identified and the individual ISO/RTO cost allocation procedures have been substantially finalized by the Commission. Stakeholders expressed different views regarding the schedule and timing for addressing such cost allocation issues. The JIPC is holding to this plan and a summary of existing regional cost allocation methods is included in the NCSP.

- The existing economic planning processes and cost allocation methodologies in the three regions were discussed in detail at the June 30, 2009 IPSAC meeting. If justifications for individual projects are identified, there are several means available in the existing ISO/RTO tariffs to pay for the projects. (Q3-2009)

October 19, 2009

Northeast ISOs Seams Resolution Report

History of Completed Seams Projects

2000 – Completed Projects

1. **May 2000 – NY EMERGENCY TRANSFER AGREEMENT WITH PJM** – ensures that energy will flow across control area boundaries during emergency situations

2. **June 2000 - NYISO DATA FEED FOR PJM E-DATA TOOL** – provides NY zonal and generator LBMP data electronically for display on PJM's e-Data tool.

3. **August 2000 – NY EMERGENCY TRANSFER AGREEMENTS WITH ISO-NE** – ensures that energy will flow across control area boundaries during emergency situations

4. **Sept 2000 – NY PREVENTION OF TRANSACTION BID PRODUCTION COST GUARANTEE GAMING -** by scheduling transactions in NY and canceling them (or not scheduling them) in neighboring control areas, resulting in improper payments in NY and ramping difficulties in PJM. Immediate corrective action taken with a permanent fix implemented in the NY market software making this gaming scheme unprofitable.

2001 – Completed Projects

5. **Jan 2001 – PJM CHANGES TIMING REQUIREMENTS –** PJM implemented new business rules to allow schedule changes through the Enhanced Energy Scheduling (EES) system with only 20 minutes notice.

6. **Feb 2001 – NY RESERVE SHARING WITH ISO-NE –** Phase 1 allows NY to include 300 MW from ISO-NE as 30-min. reserves. Phase II (sharing of up to 100MWs of 10-minutes reserves) effective 6/15/01.

7. **March 2001 – NY TRANSACTION CURTAILMENT NOTIFICATION MESSAGES –** enhanced communication process by improving informational messages when transactions are not scheduled or curtailed.

8. **April 2001 – PJM MODIFIES NYPP-E/NYPP-W LMP DEFINITION –** PJM's NYPP-W and NYPP-E interface points are combined into a single New York Interface point. The two interfaces will continue to be used but the price at these points will be the same and reflect the definition of a single NY interface point.

9. **May 2001 – NY EMERGENCY TRANSFER AGREEMENT WITH HQ –** ensures that energy will flow across control area boundaries during emergency situations

10. **June 2001 – NY'S IMPLEMENTATION OF TRANSACTION SCHEDULING DESK** – NYISO implemented an additional scheduling position in the Control Room that can be directly accessed by market participants to address real-time scheduling questions and problems. Timely provision of information reduces business risk and facilitates a level playing field for all MP's.

11. **June 2001 – PJM IMPLEMENTATION OF CSS –** PJM implements the Collaborative Scheduling System (CSS), which is part of the EES system. It allows users to submit scheduling information to one place and the information is sent to the NY MIS system for processing.

12. **June 2001 – PJM/NY COORDINATION OF IN-DAY TRANSACTION SCHEDULES TO HELP CONTROL RAMPING ISSUES –** To help control ongoing ramping problems between NY/PJM schedules, PJM implemented an approval process for all hourly (HAM equivalent) PJM/NYISO schedules. These schedules will only be approved and hold ramp after being checked out hourly with the NY-ISO.

13. **Dec 2001 – NY MULTI-HOUR BLOCK TRANSACTIONS** - Develop process to accept and schedule external LBMP energy transactions with minimum run times. Allows a marketer to arrange the 5-day by 16-hour market products commonly offered in existing Trading Markets.

<u>2002 – Completed Projects</u>

13a. **Jan 2002 – ISO-NE AND NYISO ANNOUNCE AGREEMENT TO ESTABLISH COMMON MARKET DESIGN AND EVALUATE A SINGLE RTO –** Provides for the development of a plan to establish a common market design and to evaluate a New England and New York RTO.

14. **Jan 2002 – PJM IMPLEMENTS NYIS INTERFACE LMP –** The NYPP-W and NYPP-E interface points are converted into a single New York Interface point (NYIS).

14a. **Jan 2002 - PJM AND MISO ANNOUNCE PLAN TO DEVELOP A JOINT AND COMMON WHOLESALE MARKET –** Covers all or parts of twenty seven (27) Midwest and mid-Atlantic states, the District of Columbia, and the province of Manitoba. This removes the potential for seams over a large portion of the Eastern Interconnection.

15. **Feb 2002 – NY TRANSACTIONS PRESCHEDULING** - An external LBMP or wheel-through pre-schedule request may be submitted up to 18 months prior to the effective transaction date. A pre-schedule request is checked for ramp and ATC before being approved. It is then given economic priority in the scheduling software over other external transactions that are not prescheduled, to provide the greatest certainty that the transaction will flow. NYISO implementation of Long-term Pre-scheduling provides comparable treatment of long-term firm service with PJM firm and “non-firm willing to pay congestion” service options. Long-term pre-scheduling allows preferential (firm) treatment of transactions, consistent with PJM & ISO-NE SMD 1.0, and addresses scheduling requirements for bundled ICAP/Energy products.

15a. **April 2002 - PJM AND ALLEGHENY POWER SYSTEM FORM PJM WEST** - The larger energy market provides one market with a common transmission tariff, business practices and market tools, thus eliminating seams issues between Allegheny Power and PJM.

16. **May 2002 - ISO-NE CHANGES TO ICAP RULES** - amending procedures for submitting external ICAP transactions between ISO-NE and NYISO. The changes to ISO-NE Market Rule 4 insure that imports from NY to NE will not exceed the TTC of the New York ties.

17. **May 2002 - ISO-NE RULE CHANGES TO PERMIT/FACILITATE SNETS FROM ISO-NE TO NY** – FERC Order dated 4/26/2002; ISO-NE can use all available resources to support short notice external transactions (SNETs) as long as ISO-NE replacement reserves are not depleted in doing so. The short-notice scheduling capability gives market participants the ability to schedule new transactions on an hourly basis in a manner compatible with the hourly market. Results from Summer 2002 indicate a 31% increase in MWh exports and a 54% increase in the number of contracts from New England to New York.

18. **May 2002 – NY TRANSACTIONS REINSTATEMENT** - for transactions curtailed for in-hour due to reliability violations. NYISO will reinstate external transactions in-hour as soon as the reliability problem is resolved (previously the transaction had to wait until the next hour-ahead commitment run).

19. **May 2002 – NY HOUR-AHEAD CLOSING TIME CHANGED FROM 90 TO 75 MINUTES** - to allow for closer coordination with ISO-NE, which uses a 75-minute closing time. This allows MPs to use more current information in formulating transaction strategy.

20. **May 2002 - INTERIM TRANSACTION CHECKOUT BETWEEN NYISO AND ISO-NE** - This NYISO/ISO-NE Interim Transaction Checkout Tool addresses a seams issue requirement to enhance checkout for summer 2002 until OSS is deployed. It provides an electronic means of sharing transaction information to assist the operators during checkout and identify transaction issues more easily.

21. **May 2002 – IMO SEAMS INITIATIVES** – implemented a procedure that permits staggered HAM closing times – IMO generally closes their market to MP's 2 hours before the hour – a process is in place that will evaluate their accepted NY import/export bids in the hour-ahead commitment. Also, an interconnection agreement between NYISO and the IMO was made effective on May 1, along with several critical joint control room procedures.

22. **May 2002 – NY EMERGENCY TRANSFER AGREEMENT WITH IMO –** ensures that energy will flow across control area boundaries during emergency situations.

23. **May 2002 – NYISO FILING FOR ICAP DELIVERABILITY TO PJM** – NYISO filed with FERC on May 24 to modify its tariff to provide delivery of ICAP purchased by PJM from NY suppliers, allowing NY generators the opportunity to meet the PJM deliverability requirement and participate in the PJM ICAP market.

23a. **June 2002** – **IMO, ISO-NE, NYISO SIGN AGREEMENT TO WORK COOPERATIVELY TO HARMONIZE MARKET RULES, ELIMINATE SEAMS ISSUES AND DEVELOP LARGER MARKETS** – Goal is to develop larger markets for energy and ancillary services. Elimination of export charges is a priority.

24. **June 2002 - DISPLAY TTC/ATC FOR ALL INTERFACES ON NPCC WEBSITE** – provides market participants with a single location to view the most limiting values across neighboring control area interfaces. NPCC has developed a website where regional MP's can view in one location the TTC/ATC values for all regional interfaces.

25. **June 2002 – NY/PJM IMPLEMENT PLAN TO ENHANCE CONGESTION MANAGEMENT -** Under specific conditions between NY and PJM through control room operating procedures. The pilot provides a means to relieve congestion in western PJM by shifting generation in NYISO.

26. **June 2002 – NY AND NE AREA CONTROL ERROR (ACE) DIVERSITY EXCHANGE INITIAL DEPLOYMENT -** Intended to enhance regulation performance. Initial implementation with NYISO and ISO-NE participating; other NPCC Control Areas to participate when IT resources are available. Takes advantage of the diversity among the control areas to reduce the burden on regulating units that should aid regulation performance.

27. **July 2002 – NY IN-DAY COMMITMENT AND SCHEDULING ENHANCEMENTS -** This project implements consistent treatment of reserves in NYISO's hourly and real-time markets which will improve price convergence at the proxy (boundary) transaction busses with the neighboring control areas.

27a. **August 2002– NPCC ENHANCEMENT/EXPANSION OF LAKE ERIE EMERGENCY REDISPATCH –** NPCC FERC filing to add the MISO as a signatory and incorporate new settlement provisions.

28. **Oct 2002 (Orig. Date Sept. 2002) – NY INTERCONNECTION AGREEMENT WITH HQ/TE** – Interconnection agreement signed in October 2002. Review of potential for increasing the 7040 transmission line import limit above 1500 MW and evaluation of ways to better utilize NY-HQ-ISO-NE DC facilities are scheduled to be addressed under P5 and P14.

29a. **Dec 2002 – PJM IMPLEMENTS SPINNING RESERVES MARKET –** The spinning market for PJM was implemented on December 1, 2002. Spinning reserves consist of extra power plant generating capacity that is kept running so it can be used on short-notice to respond to increased demand or to supplement an unexpected drop in generation on the grid. Power suppliers will be paid a per megawatt hour market clearing price to provide spinning reserve services – a pricing schedule that has been approved by the FERC.

<u>2003 Completed Projects</u>

P1 **March 2003 – ISO-NE IMPLEMENTED *NE SMD 1.0*** –Under *NE SMD 1.0*, ISO-NE implemented LMP with day-ahead and real-time balancing markets similar to those utilized in PJM and NY. This was successfully implemented on 3/1/2003. (30)

P2 **March 2003 – ISO-NE UCAP IMPLEMENTATION** – ISO-NE implemented NY-based UCAP market as part of *NE SMD 1.0*. New England market's is similar to New York's schedules and auction processes. First auction held in March 2003 for April 2003 capacity market. With the opening of the ISO-NE markets, the same UCAP product is now used throughout the Northeast Region (PJM, NY and ISO-NE) (31)

P3 **March 2003 – NY NEW TRADING HUBS** - Establish trading hubs as requested by market participants to provide locations that would facilitate and enhance trading activity in the New York Market. NY market participants agree that the need for trading hubs is currently being met by the existence of the zonal LBMPs and that no further action is required at this time. (36)

P4 **April 2003) – NY OPEN SCHEDULING SYSTEM (OSS) Phase I – Deployed on 4/13/2003.** OSS is implemented as a "one-stop-shopping" tool enabling interregional transaction scheduling for external transactions between NY and PJM. Phase I deliverables include: (38)

- Submittal of bilateral transaction bids and schedules
- Pre-scheduling of available transmission and ramp
- "One-stop-shop" transaction submittal with NY MIS and PJM EES
- Enhanced transaction management tools

P5 **Q4 2003 (orig. August 2003) – NY MS-7040 Transfer Study –** NY study on the impact of MS-7040 transfers above the current 1500 MW limit is complete and recommended no change in the current limit but did recommend developing a process to assess available margins to support HAM scheduling above current MW limits.

P6 **Q4 2003 (orig. Summer 2003)** – **Maritimes to become participants in ACE Diversity Interchange process.** Completed and operational in November 2003.

P8a **Q3 2003 – NY OPEN SCHEDULING SYSTEM (OSS) Phase II – Ramp/ATC Posting**

- Integration of PJM ramp data effective 9/30/2003. PJM Ramp data now incorporated into OSS advisory Ramp / ATC displays and advisory pre-validation for pre-schedule bids.
- Ramping - Allow multiple schedule changes per hour (included in I3, Issues Under Discussion)
- ATC/TTC posting via OSS – Complete.

2004 Completed Projects

P11 **1st Quarter 2004 (Complete) - HARMONIZE NEW YORK DEMAND RESPONSE PROGRAMS WITH ISO-NE** – NYISO Demand Response staff have met several times with their counterparts in PJM and New England during 2003 and 2004 and determined that much harmonization has occurred since the original recommendations. For example:

- All three ISOs have similar emergency programs called under very similar system conditions with similar or identical price floors ($500 in NYISO and PJM, $500 or $350 in ISO-NE)
- All three ISOs have programs under which Demand Response can obtain ICAP credit by virtue of participation in an emergency/reliability program
- All three ISOs have, or plan to have, planning processes that will, in general terms, allow Demand Response to compete alongside transmission and generation alternatives to meet economic/congestion needs.
- All three ISOs have adopted Small Customer Aggregation programs that allow small customers lacking interval meters to participate in their demand response programs.
- All three ISOs presently allow on-site generation to participate in their emergency DR programs.
- ISO-NE and PJM presently allows on-site generation to participate in their economic DR programs. NYISO does not presently allow on-site generation to participate in its economic program. As NYISO was developing the planned extension to that program, neither NYISO nor a significant number of its Market Participants support allowing on-site generation to participate. Accordingly, this prohibition is intended to remain.
- All three ISOs have, or are seeking participant/FERC approval of fundamentally similar day-ahead demand response programs.
- All three ISOs are in fundamental agreement that DR has a role to play in providing ancillary services such as reserves and that DR should be appropriately integrated into each ISO's ancillary service markets. While it is

unlikely that this will take place in the next year, each ISO intends to work with its market participants toward this common end.

P20 Q4-2004 (complete) – ELIMINATION OF RATE PANCAKING (NYISO – ISO-NE)

- The elimination of export fees between ISO/RTO regions is an important objective of FERC. The NYISO and ISO-NE have been working with their TOs and state regulators to accomplish this goal. During mid-2003, the NYISO and the New York transmission owners developed principles for the elimination of export charges from the New York Control Area, subject to reciprocity. The New England transmission owners included similar provisions in the RTO-NE filing with FERC on October 31, 2003. On March 24, 2004, FERC's Order on RTO-NE was conditioned on the elimination of export fees between New York and New England by the end of 2004. In April 2004, an agreement in principle was achieved among ISO-NE, the NYISO, New York, and NE state regulators calling for the elimination of export fees between the regions on or before December 2004.

2005 Completed Projects

P7 Q2 2005 (Orig. Date Dec 2002) – COORDINATION OF CONTROLLABLE TIE LINES (PHASE-ANGLE REGULATORS) BETWEEN NY AND PJM

FERC issued an Order on the PSEG-ConEd wheeling contracts (FERC Docket EL02-23) Phase I issues 12/9/2002. Appeals of Phase I Order were denied in FERC's 12/23/03 order. The ALJ issued an Initial Decision in the Phase II litigation on June 11, 2003. Briefs have been finalized. FERC issued its final order on August 6, 2004 which requires NYISO, PJM, Con Edison and PSEG to develop an operating protocol to coordinate the scheduling of the PARS and other measures to implement the transmission service under the subject contracts to be filed with FERC by November 6, 2004**.** Con Edison and PSEG have both filed for rehearing of certain aspects of the FERC Order. PJM and NYISO have met several times to draft the operating protocols.

- On October 26, the parties filed with FERC for an extension of time (until January 17, 2005) to develop a mutually acceptable operating protocol, and proposed to identify issues they were unable to resolve by December 1, 2004. The Commission granted the joint motion in its November 1 notice.
- On December 13, 2004, the parties filed for additional time (until December 21, 2004) to identify outstanding issues in the proceeding.
- On December 22, 2004, the parties filed a joint submission of outstanding issues and requested assistance of the ALJ to help narrow their differences.
- On January 6, 2005, the parties met with the ALJ to explore outstanding issues.
- On January 13, 2005, the parties filed for an extension of time (until February 18, 2005) to resolve the outstanding issues and to finalize a mutually acceptable protocol.
- On February 18, 2005, the NYISO, PJM, and PSE&G submitted a joint compliance filing including a comprehensive operating protocol under which the NYISO and PJM would administer the subject contracts. The filing requested a June 1, 2005 implementation date.
- On May 18, 2005 FERC issued an Order approving the protocol as filed, with an effective date of July 2, 2005; the protocol was implemented on July 1, 2005

P8b Q3 2003 (orig. Projected 2003) – FACILITATED CHECKOUT

- NYISO, ISO-NE, IESO, HQ, NB, & MISO have been participating in the specification of the Facilitated Transaction Checkout (FTC) communication protocol. Pilot implementation with ISO-NE has been successful and demonstrated ISO-NE and NYISO capability to exchange transaction data in real-time. NYISO, ISO-NE, and IESO have completed implementation of the data exchange software. ISO-NE and IESO have successfully integrated the new data into their control room displays.

Milestones and timetable:

- FTC was implemented into NYISO's control room displays on July 5, 2005.

P8c Q2 2005 (orig. Projected 2004) – NY E-TAGGING

- NYISO has implemented automated tools to improve communication and updates of NYISO transaction bids and schedules with the E-Tag system. The tools allow automated response on incoming E-Tag requests and automated curtailments to the E-Tag system for bid / schedule changes resulting from hour-ahead evaluation, checkout, and curtailments.

Milestones and timetable:

- **NYISO** – Has implemented automated tools to improve communication and updates of NYISO transaction bids and schedules with the E-Tag system.
- Phase I development (operations automation) is complete and was deployed on April 25, 2004.
- Release 1.4 of the E-Tagging software was deployed February 1, 2005.
- Release 2.0 will provide more automated integration of this data, including the ability to identify and cut any MIS schedules without a corresponding E-Tag. Release 2.0 was successfully deployed on July 5, 2005.

P10 Q4 - 2005 (Orig. Date 2003) – NPCC EXPANSION OF REGIONAL RESERVE SHARING

- NPCC coordinated the implementation of a 100 MW reserve sharing pilot among NPCC members to improve regional reserve market efficiency. The NPCC RCC formally accepted the Reserve Sharing Procedure on June 1, 2005; the pilot was implemented on January 4, 2006. The RCC restricted reductions in individual Area reserve requirements to 50 MW for up to one hour. The pilot project does not address a market-based solution.

P12 Q1- 2005 (Orig. Date 2003) – NY REAL-TIME SCHEDULING (RTS) IMPLEMENTATION AND NY SMD 2.0

Real-Time Scheduling (RTS) is a major portion of the overall NY SMD 2.0 and involves developing new real-time commitment (RTC) and dispatch (RTD) software in place of the current hour-ahead commitment and real-time dispatch modules. The RTS time frame extends from 5 minutes in the future to 2½ hours in the future. Commitment and decommitment decisions are made every 15 minutes by the real-time commitment (RTC) process. Decisions to adjust the output of internal energy suppliers (dispatch) are made every 5 minutes by the real-time dispatch (RTD) process, as is the calculation of energy and ancillary services prices.

2006 Completed Projects

P23 Q2 2006 – COORDINATION OF INTERREGIONAL PLANNING

In January 2003, a Liaison Task Force was formed including all NPCC members as well as PJM to develop ways to improve the coordination of planning for the Northeast region. As a result, there has been considerable improvement in communication on planning issues. During 2004, ISO-NE, NYISO, and PJM solicited stakeholder input on a draft protocol agreement. In general, stakeholders were supportive of moving ahead with the protocol.

Milestones and timetable:

- The ISOs developed a draft coordinated planning protocol document, incorporated stakeholder input and finalized the protocol document in December 2004. This document provides the basis for standardizing data and information exchanges, developing a coordinated plan, and initiating a joint stakeholder process. The IESO, Hydro Quebec (Transenergie) and New Brunswick Power, while not parties to the protocol, have agreed to participate on a limited basis in order to ensure better coordination for the benefit of the Northeast region.

- The initial scope of work for a Northeast Coordinated System Plan began in summer 2004. It includes better coordination of information sharing by harmonizing the timing, development, and exchange of data bases and modeling assumptions used in planning analysis, the identification of joint planning issues, the establishment of standardized confidentiality agreements and building upon joint planning activities already under way.

- The initial draft Northeast Coordinated System Plan: 2005 (“NCSP 2005”) was issued to stakeholders on April 6, 2005. This report consolidates the system assessments and plans of each of the participating control areas, highlights existing inter-regional planning activities, summarizes perceived issues and risks, and identifies potential issues for future analysis.

- A region-wide planning process has been implemented which includes an open stakeholder advisory group and the issuance of a region-wide coordinated plan. This region-wide planning process is supplemental to each ISO or RTO's individual and more detailed transmission planning process.

- The first meeting of the Inter-area Planning Stakeholder Advisory Committee (“IPSAC”) was held on June 17, 2005 to receive input and to initiate the process for developing the first fully coordinated NCSP for the Northeast, which is expected to be issued after mid-2006. This plan will include joint analysis performed by the ISO/RTOs.

- Based upon input from the June meeting, the ISOs have prepared a Scope of Work for the NCSP 2006. A meeting was held on October 28, 2005 to review the scope of work with stakeholders. Preliminary results were reviewed with stakeholders at an April 27, 2006 IPSAC meeting and final results are expected to be reviewed at an IPSAC meeting scheduled for September 20, 2006. Potential interregional cost impacts associated with interregional planning studies will be addressed in future IPSAC meetings.

- The ISO/RTOs have coordinated System Impact Studies that could have an impact on neighboring Areas. The potentially affected areas are contacted at the earliest possible date and the scope of work and study assumptions are modified to reflect this input.

- A joint website has been established and the ISO/RTOs are in the process of updating posted in

2007 Completed Projects

P14 Pending (Orig. Projected 2005) – NY-HQ-ISONE HVDC INTERCONNECTIONS (ISO-NE, NYISO, PJM and HQ)

This is a joint project lead by ISO-NE and HQ TransÉnergie to update the methodology and procedures for scheduling of the Phase II HVDC interconnection between New England and Quebec.

- Initial efforts were focused on use of the IDC as a possible tool to forecast availability of Phase II above the 1200 MW limit, however the parties have concluded that the IDC in its current form would not be suitable.
- The report, "Review of the PJM-NY-NE Procedures and Methodology for the TE-NE HVDC Line was finalized May 2005". This document is posted on the ISO-NE website at http://www.iso-ne.com/trans/ops/limits/ .
- NYISO, PJM, and ISO-NE have signed a data sharing agreement
- All three recommendations in the May 6, 2005 Report are to be implemented, that is: (1) PJM will improve the calculation for the marginal Phase II limit and will implement this calculation method by the mid November - early December time period; (2) ISO-NE will post the NYISO and PJM real time limit for Phase II; and (3) an analysis for significant curtailments will be made with the ISO-NE administering the reporting function.
- ISO-NE has begun to develop the scope of work and schedule necessary for implementation.
- The posting of NYISO and PJM real time limits for Phase II (item 2 above) is scheduled for implementation in late May of this year (2007).
- A proto-type report and process for documenting significant Phase II curtailments is currently under consideration. A proposal for satisfying this recommendation will be prepared and presented at the meeting of the Joint TÉ-ISO NE Interconnection Committee.
- On May 9, 2007, ISO-NE began posting NYISO and PJM based real time limits for single source contingencies (including Phase II) in the New England Control Area.

P19 Q4-2006 (orig. Projected 2004) – ISO-NE PARTIAL UNIT ICAP SALES

ISO-NE's SMD 1.0 does not support the sale of UCAP to external control areas from portions of units. The Commission has directed that this functionality be added. ISO-NE has implemented changes that offer basic partial delisting functionality.

Milestones and timetable:

- ISO-NE presented a basic proposal for discussion with the Markets Committee ("MC") at the October 13, 2004 and December 2, 2004 MC meetings.
- A final proposal was presented to the MC for a vote in the December 15, 2004 meeting and passed with 70.48% voting in favor. The NEPOOL Participants Committee ("PC") voted at its January 7, 2005 meeting to support ISO-NE's proposal.
- Filed with FERC on January 31, 2005
- Manual changes approved by MC on March 8, 2005

- FERC issued order conditionally accepting tariff filing on March 31, 2005. Two compliance filings were required: a 30-day and a 60-day.
- Manuals were approved by MC on April 13, 2005, complying with FERC's order.
- ISO-NE and NEPOOL made the 30-day compliance filing on May 2, 2005, which was accepted by FERC on June 22, 2005.
- On May 2, 2005, ISO-NE also filed a request for rehearing of the Commission's March 31, 2005 directive to modify the partial de-listing provisions such that the requirement for partially de-listed units to offer their full capability into the Day-Ahead Energy Market (the "Offer All" requirement) will expire upon the implementation of a Locational ICAP market in New England. On September 15, 2005, the Commission issued an order granting the ISO's request for rehearing and rescinding the directive that the day-ahead Offer All requirements expire coincident with the implementation of a Locational ICAP mechanism.
- Partial unit ICAP sales were implemented on June 1, 2005.
- On November 17, 2005, the Commission directed ISO-NE and NEPOOL to continue to work on aspects of the rules relating to partial de-listing, without establishing specific deadlines. Specifically, the Commission directed ISO-NE and NEPOOL to continue to work to (1) remove the restriction that a unit be limited to a single listed and de-listed segment; and (2) eliminate restrictions associated with the treatment of partially de-listed resources in the Forward Reserve Market.
- On May 30, 2006, FERC issued an order directing ISO-NE, "within 90 days of the date of this order, to make a filing with the Commission providing a specific date on which ISO-NE will file to implement multiple segment delisting." The ISO is currently in the process of determining a target date for implementing multiple segment delisting.
- On August 28, 2006, the ISO-NE submitted a compliance filing providing for market rules to be submitted on or before March 30, 2007 (with a requested effective date of June 1, 2007) to allow sales of capacity and non-recallable energy to different buyers over different transmission interfaces.
- On March 12, 2007, ISO-NE reported to FERC that stakeholder discussions on a proposal to allow multiple sales of ICAP over multiple external interfaces from a single partially or wholly delisted resource will commence in April. Implementation of this capability is anticipated shortly after completion of the stakeholder discussions, scheduled to conclude in late spring or early summer.
- ISO-NE implemented rule changes to allow multiple sales of ICAP over multiple external interfaces from a single partially or wholly delisted resource on June 8, 2007.

P30a MODELING OF NETTED TRANSACTIONS AT THE NYISO-HYDRO QUEBEC INTERFACE (NY–HQ)

Currently, real-time imports from HQ are limited to 1200 MW based upon NY first contingency criteria. Day-ahead and real-time scheduling software recognizes a 1500 MW limit at the NY-HQ proxy bus comprised of imports, exports, and wheel-throughs. One solution that has been suggested would create a second proxy bus model at the interface, which would be used to schedule only wheel-through transactions; the first proxy bus would be used to schedule imports/exports up to a net level of 1200 MW. On December 16, 2005, the NYISO met with HQUS to discuss next steps. Based on the December meeting, a high-level presentation on functional requirements and preliminary resource requirements was presented at the Jan. 20, 2006 S&PWG meeting and at the February 9, 2006 Operating Committee meeting. The NYISO has proposed to implement a second proxy bus with HQ to account for wheel-through transactions. The HQ proxy buses will each have a ramp limit and will split the available ramp for that interface. The NYISO is currently reviewing software and modeling design requirements. The NYISO filed with FERC on March 28, 2007 and implemented the dual proxy generator bus arrangement at the Chateauguay Interface on July 1, 2007.

P30b MS-7040 TRANSFERS ABOVE THE CURRENT 1500 MW limit (NY–HQ)

A New York study on the impact of MS-7040 transfers above the current 1500 MW limit is complete and recommended no change in the current limit but did recommend developing a process to assess available margins to support HAM scheduling above current MW limits. A proposed solution was presented at the Feb. 9, 2006 Operating Committee meeting. Implementation of proposed real-time operation expected for Summer 2006 Capability period, subject to completion of Operating Studies and automated monitoring capabilities. A presentation was made to the Market Structure WG on April 13, 2006 detailing a proposed scheme for operating MS7040 transfers above 1500 MWs in real-time (http://www.nyiso.com/public/webdocs/committees/bic_mswg/meeting_materials/2006-04-13/HQ_RTM__Limit_MSWG_4_13_06.pdf). A method for operating the MS7040 transfers above 1500 MWs in real-time (subject to defined operating conditions) was implemented on 11/1/06. (Jan 2005)

P31 Q2 2007 – NYISO and PJM JOINT OPERATING AGREEMENT (JOA)

In 2007, NYISO and PJM completed a JOA which enhanced the cooperation and coordination in the following areas:

- information exchange
- emergency assistance
- operating to SOL and IROL limits
- outage scheduling
- joint checkout procedures

P32 Q2 2007 – NY/PJM PROXY BUS CLEARING PRICE CALCULATIONS

NY and PJM calculated their respective proxy bus prices using the LMP method but with fundamentally different underlying assumptions. This can result in significant price differences between the NY and PJM proxy prices. These discussions have started between the ISOs. The NYISO presented its internal proposal to improve the proxy bus pricing at a series of stake holder meetings as follows: MIWG - 11/21/06 and 1/17/07, SOAS - 1/24/07, BIC (update) - 2/7/07, OC (update) - 2/8/07 and 4/20/07. With no Tariff changes required, a technical bulletin was issued on 4/13/07 describing the details of this methodology and the operations manual will be updated along with a larger set of queued changes at a future time. The implementation of this methodology was activated on June 6, 2007.

I10 ICAP SELF SCHEDULING REQUIREMENT IN ISO-NE

Market participants have expressed concern with the self scheduling requirement in the ISO-NE ICAP Manual that requires resources sold externally to self schedule the amount of capacity they offer for sale externally in order for the associated energy to be non-recallable. The market participant concern is that this requirement may not be consistent with the ICAP principles that have been agreed upon among the Northeast ISO/RTOs and that this requirement may be an unnecessary barrier to trade. The ISO provided a report on ICAP self-scheduling to New England Participants on September 18, 2006 (http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2006/oct17182006/a12_iso_memo_re_icap_exports_and_self_scheduling_09_15_06.doc). ISO New England report on ICAP Self-Scheduling was reviewed with NEPOOL Markets Committee in October of 2006.

- The referenced report concluded that no significant seam exists in that the requirements in the PJM, NY and NE markets for resources to produce the energy being sold externally under non-recallable sales are effectively the same.

2008 Completed Projects

P25 Q2-2007– NORTHEAST GAS/ELECTRIC INTERDEPENDENCY COORDINATION (PJM, NYISO, ISO-NE)

Much of the generation built in the Northeast in recent years is fired by natural gas. Periods of extreme cold weather place heavy demands on both the electric and natural gas transmission systems as energy consumption increases. Sometimes, the resulting delivery restrictions on the regional gas pipeline system, and/or lack of firm contracting, can limit the ability of gas-fired generation to produce electricity.

- ISO-NE, NYISO, and PJM have agreed, through a Memorandum of Understanding signed in June of 2005, to collaborate to ensure electric power system reliability in the event of supply constraints on the natural gas supply system. The ISOs will coordinate operations and practices and share information and technology during periods of extreme cold weather and/or abnormal natural gas supply or delivery conditions through the Northeast ISO/RTO Natural Gas and Electric Interdependency Coordination Committee (“NGEICC”).

- Following hurricanes Katrina and Rita in the fall of 2005, and as a result of the devastating impacts those hurricanes had upon the oil, natural gas and refining infrastructure in the Gulf of Mexico, the NGEICC initiated an assessment of the potential impacts on regional fuel supply/delivery, as it relates to power generation fuels and subsequent reliability of the electrical power grids in the northeastern United States. The Committee retained the services of an industry consultant for this analysis. The consultant delivered study results for ISO-NE, NYISO, and PJM. The study predicted a delivery shortfall of approximately 1.5 Bcf/day through the winter season. That prediction turned out to be accurate, but the mild winter weather blunted any impact from the delivery shortfall.

- ISO-NE and NYISO have established mechanisms to automatically receive regional natural gas pipeline (Transportation Service Provider’s (“TSP”)) informational postings from their electronic bulletin boards (“EBB”). TSP informational postings contain Critical and Non-Critical Notices as well as Planned Service Announcements, detailing maintenance activities. PJM is now monitoring various sources of information to assess the natural gas delivery situation.

- PJM is now participating in the Mid Atlantic contingency planning group, which is a gas supplier/user group and continue to monitor the supply situation.

- NYISO is working with the New York Department of Public Service, select Transmission Owners and select Local Distribution Companies to finalize a communication protocol to be used in the event of severe natural gas restrictions in New York City and/or on Long Island. Under the protocol the NYISO would receive notification of operational flow orders (OFO) issued for New York City and Long Island and keep the Local Distribution Companies in New York City and on Long Island appraised of the status of the electric system. A draft version of the protocol has been shared with Market Participants.

- On February 1, 2008 NYISO filed Tariff updates with FERC to incorporate a New York State Gas-Electric Coordination Protocol into its OATT. The Coordination Protocol establishes communication pathways in the event of a gas or electric emergency in the State of New York between the local distribution companies serving gas fired generation plants, the power plant operators of gas fired generation plants, the Transmission Owners, the NYISO and the Staff of the New York State Department of Public Service. In addition, the NYISO submitted a Statement of Full Compliance with NAESB WEQ Standard 011-1.6 /WGQ Standard 0.3.15 as required by FERC Order 698. On March 28, 2008 FERC accepted the NYISO Tariff filing.

- With the projected increase in imported LNG deliveries being re-gasified to supplement domestic North American gas supplies, on June 15, 2006, FERC issued a Policy Statement on Natural Gas Quality and Interchangeability (Docket No. PL04-3). Concerns have been expressed over the interchangeability and potential impacts on end-users due to various sources of global LNG supplies as compared with the historical composition of domestic natural gas. FERC delineated five (5) guidelines or principals and mandated the updating of each natural gas pipeline's gas quality tariff for interchangeability with new LNG supplies.

- With respect to monitoring the interests and concerns of regional gas-fired generation and simultaneously assessing the potential impact on bulk power system reliability, ISO-NE has been following several stakeholder collaboratives being driven by the regional pipelines. These stakeholder collaboratives have been working to gauge the impacts of LNG interchangeability with respect to end-user - "sensitive receptors," while trying to find common-ground on revisions to their gas quality compositions within these tariffs. ISO-NE will continue to monitor these regional developments and share its findings with NYISO and PJM."

- In the fall of 2007, ISO-NE, NYISO and PJM collaborated to implement “common” measures in order to comply, by November 1st, 2007, with the mandates identified in FERC Order 698. FERC Order 698 requires improved coordination between natural gas and electric utilities in order to improve communications about scheduling of gas-fired generators, through incorporating certain standards promulgated by the Wholesale Gas Quadrant (WGQ) and the Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB). On September 27, 2007, New England’s Electric/Gas Operations Committee, which is comprised of representatives of ISO-NE, NYISO and the regional natural gas industry (as coordinated through the Northeast Gas Association), approved its revised “Electric/Gas Operations Communication Protocol” which supports the compliance measures of FERC Order 698. Subsequently, on November 1st, ISO-NE and PJM both filed a statement of compliance with Order 686 with FERC. On that same date, NYISO submitted to FERC a statement of partial compliance and requested a three (3) month extension in order to finalize several draft communications protocols with regional stakeholders. It is anticipated that NYISO will be compliant with FERC Order 698 by February 1, 2008. In addition, ISO-NE, NYISO and PJM coordinated efforts to request information about service levels for natural gas supply and transportation from their gas-fired generation as approved by FERC in Order 698. This information will assist reliability coordinators in assessing the relative reliability of various gas-fired generators. ISO-NE has also begun working with regional natural gas pipelines and gas LDCs to improve information sharing regarding the scheduling of transmission, generation and natural gas (transportation & distribution) maintenance activities. This process adheres to the appropriate confidentiality provisions within both the gas and electric sectors.

- On February 20, 2008, the Electric/Gas Operations Committee (EGOC) held a public workshop entitled, *"2008 Electric/Gas Operations Communications Workshop."* The EGOC is co-chaired by representatives of ISO-NE and the Northeast Gas Association (NGA), and is open for participation to all regional stakeholders. The EGOC promotes the education, understanding, coordination and communications between the regional (wholesale) electric and natural gas industries. The *2008 Electric/Gas Operations Communications Workshop*, held at ISO-NE, had over 30 attendees, which included electric sector representatives from ISO-NE, NYISO and PJM. Natural gas sector representatives included regional interstate pipelines, LDCs, and NGA. Workshop discussion primarily focused on improving the existing communications between electric control room operators and gas control operators, with respect to both verbal protocols and electronic information exchange. Both sectors highlighted their FERC Rules regarding Standards of Conduct, Antitrust Compliance, and non-dissemination of Confidential Information. In an effort to improve bi-directional communications protocols, ISO-NE Operations Staff will visit the control rooms of all regional interstate natural gas pipelines companies.

P35 DYNAMIC RAMP ALLOCATION BETWEEN PROXY BUSSES AT THE NYISO-HYDRO QUEBEC INTERFACE

There are two proxy buses available for scheduling transactions at the NYISO-HQ interface. One proxy bus is available for scheduling import/export transactions into and out of the New York Control Area. The other proxy bus is available for scheduling wheel-through transactions sourced or sunk in another control area. This dual proxy bus arrangement was implemented to remove a barrier to the full use of TTC (Total Transfer Capacity) on the interface while still enforcing the 1,200 MW import limit based on NYCA reserve requirements. The allocation of ramp capacity between the import/export and wheel-through proxies is currently assigned on a fixed basis. Providing for the dynamic allocation of ramp capacity between the two proxy buses will allow for more efficient transaction scheduling at the interface by allowing ramp capacity for the interface to be allocated between the two proxy buses in the economic evaluation of transactions schedules.

- The NYISO is actively pursuing the development of software enhancements necessary to implement the dynamic allocation of ramp between the two proxy buses. The software development and testing is expected to be completed in time for deployment in the fourth quarter of 2008.

- Software enhancements to implement dynamic ramp allocation were deployed in September 2008. NYISO Operations will change from the static ramp limits to dynamic ramp during a transition period. Market Participants will be notified each time ramp limits are changed.

2009 Completed Projects and Closed Projects

P9 LAKE ERIE SYSTEM REDISPATCH PROJECT IMPLEMENTATION

This NPCC procedure allows the redispatch of suppliers across regions to alleviate the potential curtailments of transactions due to TLR requests whenever a control area is in an energy short situation. The project requires implementation of operating procedures and billing and settlement process to account for the regional redispatch.

- PJM, NYISO, MISO, and IESO have finished analyzing the causes of high circulating flows and have provided a report with recommendations http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf.

- The second phase of PJM and MISO's loop flow study to identify the sources of high circulation on specific flowgates was completed in November 2008. This study report and presentation materials can be found at http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-loop-flow-phase-ii-study-report-final-20081112.pdf and http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-item-3c-loop-flow-phase-ii-study-presentation-v3.pdf.

- This project has been moved to the closed list. P36 Long Term Solution for Lake Erie Loop Flows is being used to report on efforts to develop solutions to mitigate Lake Erie loop flows. (Q3-2009)

P15 REGIONAL RESOURCE ADEQUACY MODEL (RAM) GROUP

The Regional Resource Adequacy Model (RAM) Working Group (formerly the JCAG Working Group) was set up to develop longer-range UCAP markets in NY, PJM and ISO-NE than currently exist. The RAM Working Group developed initial recommendations in mid-2002. The work plan was reassessed in light of the SMD NOPR and the ISOs/RTOs filed joint comments addressing resource adequacy on January 10, 2003. The comments described a central market-based resource adequacy framework, which was consistent with the goals of the SMD NOPR. NERA was selected to analyze the proposed central resource adequacy market design, and presented their final report at the February 26 regional RAM meeting. A NYISO status report was filed with FERC on February 27, 2004. The broad range of concerns raised by stakeholder groups in each ISO/RTO make it unlikely that all of the ISO/RTOs would adopt the RAM proposal as it was then currently formulated. It was anticipated that this effort would lead, instead, to enhancements in the capacity markets in each region. In enhancing their existing markets, the ISO/RTOs have committed to maintain the ability to trade the same product (UCAP) between regions and to identify and remove any remaining barriers to the trading of capacity between regions. Each region has Resource Adequacy/ICAP working groups looking at this issue.

- The NYISO submitted a hybrid proposal to its stakeholders for consideration which incorporates a voluntary forward capacity market for procurement of a portion of its future resource requirements.

- On June 16, 2006, the Commission issued an order approving the proposed capacity market settlement agreement for the New England region, which provides for the eventual implementation of a forward capacity market after an interim transition period that begins on December 1, 2006.

- PJM introduced a proposal for a Reliability Pricing Model ("RPM") in June 2004 and has subsequently presented and revised the proposal at numerous stakeholder meetings. The proposal has been presented and discussed with its Members Committee, at FERC and at its jurisdictional commissions. PJM has presented training programs and tutorials to members and interested parties.

- Beginning on December 8 and ending on December 10, 2008, ISO New England conducted the second New England Forward Capacity Market Auction for the Capacity Year beginning June 1, 2011 and ending May 31, 2012. ISO New England's Second Forward Capacity Auction Results Filing may be viewed at: http://www.iso-ne.com/regulatory/ferc/filings/2008/dec/index.html.

- PJM introduced a proposal for a Reliability Pricing Model ("RPM") in June 2004 and has subsequently presented and revised the proposal at numerous stakeholder meetings and has discussed the proposal with various PJM states PUCs. PJM has discussed the proposal with the NY PSC, with the NYISO and with MISO to ensure that the RPM proposal would not impact seams or create adverse impacts on regional markets. PJM filed its RPM proposal with FERC on August 31, 2005 and FERC held a technical conference on RPM on February 3, 2006. In an order on (Docket Numbers EL05-148-000, ER05-1410-000) April 20, the FERC endorsed the major principles of RPM. It called for the technical conference and hearings, which were held on June 7th and June 8th, to help resolve details prior to implementing RPM in place. RPM Settlement Proceedings were initiated in mid-June 2006. Parties filed proposed settlement on Sept 29, 2006 which is expected to be contested by a few parties in opposition. On December 21, 2006, FERC approved, with conditions, the RPM Settlement Agreement. The December 21st Order also denies rehearing of the Commission's finding of the April 20 order that PJM's current capacity market rules are not just and reasonable. PJM's first RPM auction began on April 2 and closed on April 6. It was for delivery of capacity during the 2007/2008 planning year (June 1, 2007 to May 31, 2008). The auctions procure needed capacity after participants have specified self-supply and contracted (bilateral) resources. Generally, annual auctions will procure capacity three years prior to the required need to provide opportunity for planned resources to compete to supply the needed capacity service. PJM's long-standing capacity requirement ensures that there are sufficient resources in place to meet the peak demand for electricity plus a reserve margin. PJM members can use generation, transmission or demand response, including energy-efficiency programs. They can meet their supply requirements by owning resources (self-supply) or contracting for them (bilaterals). PJM's analysis shows that the RPM will yield lower costs overall than the previous model. The intent of RPM is to send pricing signals that will attract investment in new capacity resources where they are most needed further enhancing reliability. The 2007-2008, 2008-2009, 2009-2010, 2010-2011 and 2011-2012 Base Residual Auction Reports and the 2008-2009 Third Incremental Auction Report are located on the PJM website under the corresponding Delivery Year headings: http://www.pjm.com/markets/rpm/operations.html.

- PJM commissioned a study in accordance with Open Access Transmission Tariff requirements to evaluate the performance of the Reliability Pricing Model in addressing the infrastructure investment issues identified by PJM and stakeholders in 2004-2006. The study report was released on June 30, 2008 and may be viewed at: http://www.pjm.com/documents/ferc/documents/2008/20080630-er05-1410-000.pdf.

- Following the issue of the Brattle Group Report on the Effectiveness of the Reliability Pricing Model in June 2008, PJM commissioned a stakeholder process to evaluate potential changes to the RPM market rules. Comprehensive proposals were created included changes to the RPM auction process design, the penalty structures, the types of resources that may participate, and the basis price that will factor into what the cleared resources will be paid (aka Cost of New Entry). None of the comprehensive proposals achieved super-majority in the stakeholder process. PJM subsequently filed with FERC to initiate a settlement process. The first meeting was held on December 16, 2008.

- The first RPM settlement meeting was held on December 16, 2008 in front of a FERC Administrative Law Judge. Settlement talks ended in January 2009, when parties established that agreement between them would not be possible. In February 2009, PJM filed with FERC a settlement agreement among some parties to resolve the issues at hand. PJM requested that FERC issue an order no later than March 27, 2009 so that changes could be implemented in time for the May 2009 RPM auction for the 2012/2013 Delivery Year.

- PJM has reconvened the Capacity Market Evolution Committee to address compliance items as directed in the March 26, 2009 FERC Order on the Reliability Pricing Model. The stakeholder group will investigate automated methods for updating the Cost of New Entry, which serves as the basis for price on the capacity market demand curve. The committee will also review the following issues: scarcity pricing revenue offset, incremental auction design, establishment of new Cost of New Entry regions, and longer-term issues. The FERC Order directs PJM to make compliance filings on September 1, 2009 and on December 1, 2009 to address various aspects of the capacity market design. (Q2-2009)

- Presentations were made by ISO-NE and PJM describing their FCM and RPM approved market designs at NYISO November 2nd and 17th, 2007 ICAP Working Group meetings.

- Further to the NYISO Board's direction, the NYISO presented to the ICAP Working Group, at meetings during 2008 and Q1 2009, an iterative design of a forward capacity market.

- The NYISO has engaged NERA to develop a conceptual forward market design.

- At the joint NYISO Board of Directors Management Committee meeting on June 10, 2008, and during several ICAP Working Group meetings in 2007, 2008, and Q1 2009, market participants expressed a range of views on the forward capacity market design proposed by the NYISO and two market participants presented alternate designs concepts.

- The present design presented by the NYISO for its stakeholders' consideration incorporates a voluntary forward capacity market for procurement of a portion of future resource requirement.
  The general design includes:

  Advance Auctions
  - Approximately 75 and 60 months prior to commitment year
  - Voluntary two sided auctions

  Forward Procurement (FP)
  - Certifications approximately 50 months prior to commitment year
  - FP approximately 44 months prior to commitment year
  - Primary purpose is for NYISO to ensure that capacity committed to market is adequate and regulated solution need not be triggered

  Reconfiguration Auctions
  - Physical Reconfiguration Auction - covers load forecast changes, replacement of FP capacity failing to meet milestones - held at y-37 months, y-23 months and y-10 months and accelerated if there was a significant failure of qualified capacity
  - Voluntary Reconfiguration Auction - to allow reconfiguration of positions taken in the voluntary auctions (e.g., marketers)

  Strip Auction (conceptually unchanged from current design)
  - Annual auction held before spot auctions

  Spot Auction (conceptually unchanged, frequency may be reduced from monthly to less frequent)
  - Would use Demand Curve

- Work on remaining design elements is continuing in Q1 and will continue is Q2 2009.

- In Q1 2009, the NYISO engaged The Brattle Group to conduct a comparison of the costs and benefits of the contemplated forward capacity market design to the NYISO existing capacity market. The Brattle Group's analysis will include information received during stakeholder sector focus group meetings it will conduct in April 2009. The Brattle Group's draft report will be presented at the NYISO's ICAP Working Group meeting on May 8, 2009, and the final report will be presented at the June 5, 2009 ICAP Working Group meeting.

- The NYISO plans to present a forward capacity market proposal to the Business Issues Committee for vote. The outcome of that vote will determine the degree to which resources are committed to fully develop FCM market rules and tariff language.

- At the March 19, 2009 ICAP Working Group meeting, the NYISO presented details on qualifications and milestones for new entry to participate in a forward procurement auction, In-City mitigation, credit requirements, settlement rules and seasonal variations issues associated with the forward capacity market design proposal, and revisions to the demand curve setting process.

- The Brattle Group presented the cost benefit evaluation report for replacement of the NYISO's existing Installed Capacity (ICAP) market with a new Forward Capacity Market (FCM) to the ICAP Working Group meeting on June 5, 2009. The evaluation report was based on three key inputs; stakeholder comments from sector focus group meetings, the PJM and ISO-NE experience with FCM development, and economic theory and literature relevant to forward capacity markets. The report concludes that a mandatory forward capacity market could have greater long-term net benefits than the existing ICAP market. However, the incremental benefits would not be reaped until new capacity is needed. The NYISO's most recent Reliability Needs Assessment (RNA) base case projects capacity surpluses through 2018. Monitoring both the PJM and ISO-NE experience with their forward market design would provide additional experience to guide the development of a FCM for NYISO. Deferring the development of an FCM market design would allow the NYISO to allocate resources to other high priority capacity market enhancements. (Q2-2009)

- At the June 10, 2009 NYISO Business Issues Committee Meeting (BIC) meeting the NYISO conducted an advisory vote to ascertain Market Participant interest in further development of functional requirements for an FCM. A majority of NYISO Market Participants supported ending the current FCM development work. The NYISO will continue to monitor the progress of neighboring forward capacity market designs. (Q2-2009)

- This project has been moved to the closed list. PJM, ISO-NE and NYISO all have capacity markets in place that provide for cross border capacity sales. The Regional Resource Adequacy Working Group is no longer active. (Q3-2009)

P18 NYISO AND ISO-NE – INTRA-HOUR TRANSACTION SCHEDULING (ITS) (INCLUDING PARTICIPANT DRIVEN AS WELL AS VIRTUAL REGIONAL DISPATCH (VRD) SOLUTIONS)

ITS is intended to provide a means to respond to excessive and persistent price differentials between the markets at times when sufficient capacity remains available on the transmission interface to provide substantive reduction in the differential. Due to market rules associated with transaction scheduling that require over one hour of advance notice to schedule a transaction and the associated risks to market participants, price differences are not well arbitraged in real-time by Market Participants (MPs).

- NYISO and ISO-NE have documented a technical definition of a virtual regional dispatch process and have received potentially viable alternative methodologies from their stakeholders. The ISOs will proceed with further stakeholder meetings to finalize the technical definition and to work towards a joint stakeholder acceptance of the proposal.

- The first set of pilot tests were conducted on April 20-21, 2005. Any additional tests will be scheduled based upon results evaluation of the April tests.

- NYISO and ISO-NE issued a report on the first pilot test on October 24, 2005. A joint meeting of NY and NE stakeholders to review the pilot test report and further develop market participant based proposals for improving the efficiency of the NYISO/ISO-NE interface was held on November 14, 2005. Based on discussions at that meeting, ITS will be considered along with other market issues as part of the NYISO rules assessment initiative currently underway.

- Prior to the interruption in ITS activity a participant-initiated proposal for intra-hour transaction scheduling was under consideration. (http://www.nyiso.com/public/committees/documents.jsp?com=bic_mswg&directory=2005-01-18&cols=5&rows=5&start=26&maxDisplay=999). The proposal would allow transactions to be scheduled on shorter notice and, potentially, for shorter duration. The shorter timeframes would allow participants to more quickly respond to price differences between the two areas.

- In 2007 NYISO evaluated inter-market real-time transaction scheduling as part of an evaluation of scheduling and dispatch market rules. http://www.nyiso.com/public/committees/documents.jsp?com=bic_miwg&directory=2007-05-24&cols=5&rows=5&start=1&maxDisplay=999. A resumption of ITS efforts would then consider any potential changes recommended by the NY rules assessment. Both NYISO and ISO-NE have high priority, large projects underway that preclude activity on Intra-hour Transaction Scheduling before 2008.

- NYISO and ISO-NE will jointly perform an analysis of the impact of uneconomic interchange between the NYISO and ISO-NE control areas. This analysis will attempt to identify the potential economic benefits of more efficient use of available interface transfer capacity. The ISO's intend to bring the results of this analysis forward to stakeholders for review and feedback. NYISO and ISO-NE will work together to identify market mechanisms that can lead to more efficient scheduling and dispatch across the interface between control areas.

- On June 23, 2008, the NEPOOL Participants Committee voted to support an ISO-NE proposal to allow intra-hour scheduling of transactions with neighboring control areas. Rule revisions to implement this change will be filed with the FERC in July 2008. Initially ISO-NE expects to implement this scheduling functionality at the New Brunswick interface. These rule revisions were approved by the FERC on September 30, 2008 (Docket # ER08-1277-000) to be effective on October 1, 2008.

- The NYISO's 2007 State of the Market Report provides an analysis of scheduling and pricing patterns at the NYISO's interfaces with neighboring control areas. This analysis indicates that there is an opportunity to increase the efficient use of transfer capacity during unconstrained periods resulting in both production cost and net consumer benefits in both control areas. The analysis indicates that reducing the transaction scheduling lead time would enable market participants to more efficiently schedule transactions. The report recommends the development of processes to improve coordination between the ISOs even if only during limited circumstances, such as reserve shortages.

- On October 10, 2008, the NYISO presented a proposal for a reserve shortage protocol. The protocol would allow for the curtailment of RTC export transactions to maintain adequate reliability based Operating Reserves due to unforeseen events until normal market transaction scheduling has an opportunity to solve for these events. The NYISO is in the process of developing revisions to its Operational protocols to accommodate this process. The NYISO intends to present additional details and responses to questions at stakeholder meetings in early 2009.

- The NYISO reviewed the Reserve Shortage Operating Protocol proposal with market participants at the January 5, 2009 Market Issues Working Group and the January 20, 2009 System Operations Advisory Subcommittee meetings. The protocol was also discussed at the February 20, 2009 Market Issues Working Group meeting. Revisions to operating procedures and training materials are under development. Implementation of the protocol is expected in the second quarter of 2009. The NYISO also met with ISO-NE operational staff to review the proposed changes.

- On June 1, 2009 the NYISO implemented a new operating protocol for handling RTC export transactions to ISO-NE during times of reserve shortages. The reserve shortage operating protocol states that if a deficiency of 10 minute Operating Reserves (East 10 and NYCA 10) occurs, or is forecasted to occur, for a sustained period, as a result of an unforeseen event, the NYISO may curtail RTC scheduled export transactions to ensure adequate reserves are available to meet requirements. ISO-NE already has an operating protocol in place to address reserve shortages through curtailment of export transactions. Specific details of this protocol were discussed with Market Participants at the NYISO's Market Issues Working Group (MIWG) meetings and in the System Operations Advisory Subcommittee (SOAS) meetings on May 6, 2009 and May 20, 2009 respectively. On June 23, 2009 a draft Technical Bulletin, #187-Reserve Shortage Operating Protocol was posted to the NYISO website and distributed to Market Participants for review and comment. (Q2-2009)

- The NYISO is assessing the feasibility of a project to enhance interregional transaction coordination by offering dynamic transaction scheduling capabilities at the NYISO borders. This concept would provide Market Participants with the ability to submit flexible transaction schedules for evaluation on an intra-hour basis. Development of this capability is initially targeted for the HQ interface with the roll-out to additional interfaces in future phases. Future phases of the project may provide for the sale of reserve and regulation products; however, this functionality is not within scope of the current design effort. At the June 26, 2009 Market Issues Working Group (MIWG) the NYISO presented an overview of this concept. (Q2-2009)

- This project has been moved to the closed list. A new project, P37 *Enhanced Interregional Transaction Coordination*, has been added to the report. This project will cover efforts to improve the coordination of energy scheduling at the borders between control areas. (Q3-2009)

P34 LIMITATIONS DUE TO LOSS OF LARGE SOURCE

ISO-NE has historically limited resources above certain MW levels when tripping at higher outputs could result in reliability problems for one of the other northeastern markets. PJM, NYISO and ISO-NE have filed a joint protocol with FERC on the coordination of loss of source procedures (http://www.iso-ne.com/regulatory/ferc/filings/2006/dec/er07-231-000_12-22-06_iso_phase_ii.pdf). On January 12, 2007, the Commission issued an order in docket no. ER07-231-000 accepting the joint protocol, without suspension after 60 days notice, effective January 16, 2007. The Commission found, however, that it should have been filed under Section 205 of the FPA and directed the RTOs/ISOs to resubmit the Protocol on tariff sheets. The RTOs/ISOs complied with this directive on February 12, 2007. On May 21, 2007, the Commission issued an order accepting the tariff sheet revisions for the Phase II Procedure, with an effective date of January 16, 2007.

- Operating studies of the loss of source, including the Phase II HVDC line connecting Quebec and New England, have been updated and approved. Planning studies simulating loss of source events have been updated. The results of these studies were reviewed at the March 23rd Inter-Area Planning Stakeholder Advisory Committee meeting.

- Analysis of potential of short-term transmission changes (series reactors) that could relieve the severity of the loss of source contingencies have been shown to produce marginal benefits and to introduce potential operating problems. They were discussed at the December 14, 2007 stakeholder meeting and it was agreed that these changes should not be pursued.

- Draft results of a long term assessment of the transmission system that reflects major improvements planned for NYISO, PJM, and ISO-NE were presented at the June 27, 2008 IPSAC meeting.. This assessment includes a determination as to their effect on the limitations on the size of allowable source loss in New England. The analysis also identifies the technical feasibility of mitigating the loss-of-source through the use of voluntary load shedding. Compatibility of such a mechanism with existing reliability rules must also be determined. The preliminary results suggest that the loss of source limit could potentially increase to a 1,500 MW to 1,600 MW level by the 2012 timeframe. A pre-feasibility study that determines the impacts of upgrading the Plattsburgh-Vermont tie to 230kV and of adding a 345kV tie between Southwest Connecticut and Westchester was also discussed with stakeholders. These improvements could result in a further increase in the loss of source limit. Additional study results will be discussed at an IPSAC meeting planned for the 4th quarter 2008. As needed, further analysis will then identify and analyze representative system improvements for discussion with stakeholders in 2009.

- Current plans call for presentation of more detailed study results at the December 2008 IPSAC meeting. These will more fully evaluate the impacts of 500kV transmission improvements in PJM and a potential upgrade of the Plattsburgh-Vermont tie.

- A status of more detailed loss of source studies was presented at the December 11, 2008 IPSAC meeting. With the addition of the planned 500kV improvements by 2012, the loss of source limit will likely be constrained by limitations in the PJM system to the 1,500 MW level. At 1,600 MW, the New York constraint will become less binding than the PJM constraint at that time. Loss of source analysis is continuing as a part of other interregional studies, such as the NY-VT tie, and the NJ- Southeast NY studies referenced in P26. The loss of source issues and studies are summarized in the NCSP and will be included in ongoing JIPC analysis reported under P26. This item as separate and distinct is considered closed. (Q3-2009)

Document Content(s)