

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.

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. 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 schedule 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 creates 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.
 - 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 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.

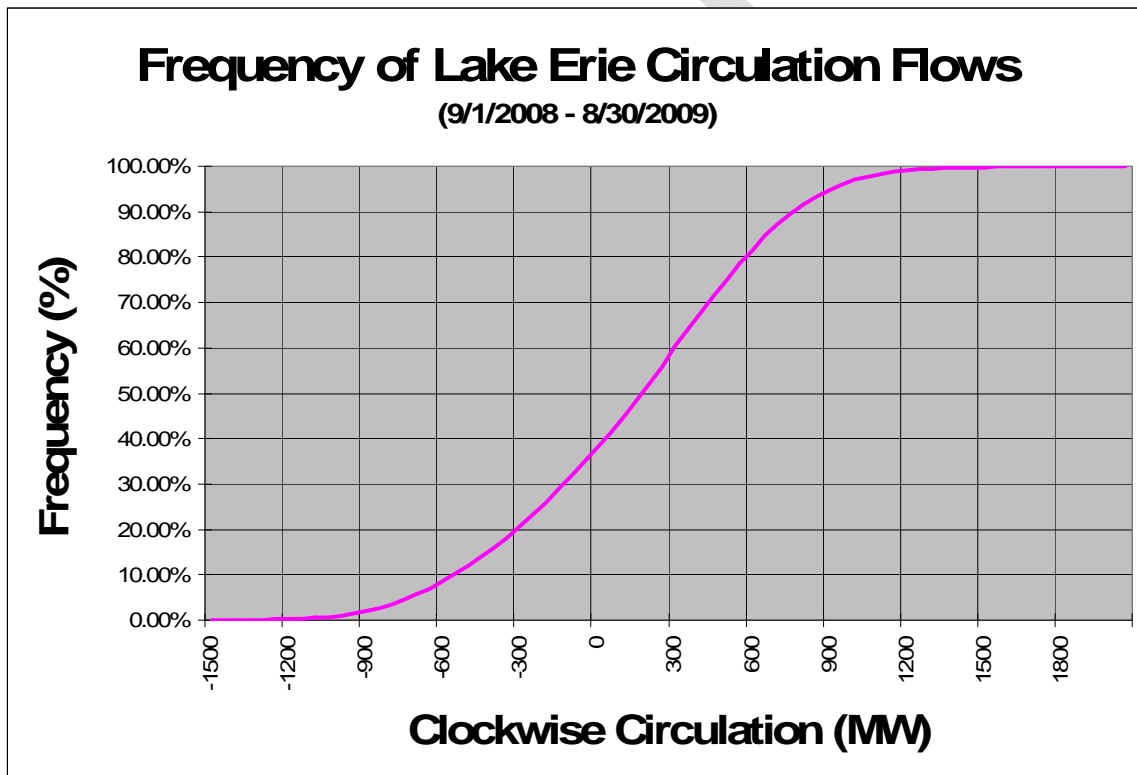
ii. Operating protocol

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-230-2.

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. Coordination Operation of Power Control Devices

The operation of the Phase Angle Regulators (PARs) by the four markets around Lake Erie can influence the amount of circulation flows as the PARs will alter the impedances on the system thereby causing a different distribution of the flows on parallel electric paths. Since uncoordinated operation of the PARs could increase circulation flows, it is important that the coordinated operation of PARs by the four markets around Lake Erie be 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 and should be considered for coordination in solutions to loop flows.

The effective management of loop flow is a substantial challenge, and it impacts both reliability and economics. The power system can be operated more efficiently and reliably when all flows are properly accounted for based upon the physical characteristics of the transmission grid. The unscheduled flow patterns caused by both lack of adequate data reporting and by the contract path scheduling approach create significant inefficiency and operational challenges.

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 circuitous scheduling path prohibition was necessary as there were no other mechanisms readily available 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 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 assign and recover 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. Firm Transmission Allocations

(To be determined - Discussions ongoing regarding opportunities to improve firm transmission allocation methodologies)

4. Market Solutions

a. Buy-Through of Congestion

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 over.

Managing power that flows in a manner that is not consistent with the path over which it is scheduled (contract path) can be a costly endeavor when it causes congestion on prime transmission corridors. Removing the unscheduled 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 processes do 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 congestion can be calculated and appropriately allocated to the scheduled power transfers that caused the congestion.

The objective of Buy-Through of Congestion is 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 regions locational marginal prices, and (c) allocate those costs to the transacting parties or curtail the associated schedules if the scheduling entity does not want to pay the full cost of flowing its transaction(s). The Buy-Through of Congestion processes will result in a more accurate reflection of the costs to move power between regions and provide an economic alternative to the administrative curtailment processes.

i. Market Flow Calculation

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 metered 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 working group anticipates a recommendation for the solution to the NERC Operating Reliability Subcommittee (ORS) at its November 2009 meeting. 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.

There are currently no NERC compliance obligations to report the necessary data to support the current IDC protocols. However, MISO and PJM currently report their market flows to the IDC and are subject to curtailment of these flows through this process. NYISO intends to undertake the additional data reporting obligations that will be necessary to support the market flow visualization efforts. 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 ISOs/RTOs that are responsible for this paper support the accurate, complete and timely reporting of the necessary information in support of the market flow calculation process.

ii. 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. It 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 and curtailing the transaction in recognition of the transaction's loop flow impacts, the resulting 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.

iii. Monitoring ISO Duties

Each Balancing Authority will be responsible for monitoring their flowgates, and when congestion is identified on those flowgates, for utilizing the Market Flow Visualization tools for determining if the 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 coordinate with the respective Responsible Control Area(s) to initiate a review of the schedules. 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).

iv. 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 and the risks associated with their predictions. The allocation of congestion costs for transaction impacts incurred by off-contract path regions to the traders will present an addition cost risk that 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 transaction party indicates it is not willing to pay congestion charges its transaction will be curtailed by the Responsible Control Area when the off-contract path flows created by the transaction adds to the congestion costs in a neighboring ISO. Once curtailed, the transaction will not be reinstated until the neighboring ISO indicates that the congestion on the impacted flowgate has been removed. Transaction that are not willing to pay congestion charges will not incur charges for the period of time necessary to remove the transaction after congestion is identified.

There will not be the ability to specify a real-time “up-to” congestion component indicating the maximum amount of off-contract path congestion the entity scheduling a transaction would be willing to pay for. Implementation of this product is not viable

given the continuous adjustment in market clearing prices that occur throughout the region, the complexity involved with multiple ISOs applying congestion charges for loop flow impacts and the operational uncertainty associated with continuously adjusting interchange values.

v. 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.

vi. Transaction Removal Process

The removal of transactions will be accomplished through a coordinated process between a Monitoring ISO and the Buy-Through of Congestion Responsible Control Area(s). A Monitoring ISO maintains responsibility for ensuring their respective systems are operated to specified reliability standards. Upon detection of a constrained flowgate, 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 of the in-service Phase Angle Regulators to conform actual power flow to schedule flow. 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 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. This calculation will be performed within the IDC.

The Monitoring ISO will communicate with the Responsible Control Area(s) to initiate a review and curtailment of the set of transactions creating loop flow impact on the constrained flowgate. 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.

The NERC TLR procedures will remain as an active viable tool to the system operators to address system overloads. TLR procedures will not be impacted by the existence (or not) of buy-through of congestion provisions. Buy-Through of Congestion will 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 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.

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. 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.

ix. 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 Market 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. Under abnormal flow conditions, the 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 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.

x. Payment for Congestion Relief

Loop flows which are having a counterflow impact on (relieving) prevailing flows will result in lower net flows on flowgates and reduced congestion management costs. It is not anticipated that Buy-Through of Congestion will identify and provide compensation for off-control path counter-flow that results from energy transfers. Traders that desire to be compensated for providing congestion relief will need to explicitly represent those transactions in the relevant market that are expected to benefit from 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.

b. 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:

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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.i, under Buy-Through of Congestion)

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

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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:

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

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:

$$\text{Payment} = ((\text{Firm Flow Entitlement MW2} + \text{Approved MW3}) - \text{Real-Time Market Flow MW1}) * \text{Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution}$$

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).

c. Enhanced Interregional Transaction Coordination

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.

d. Market Modeling

i. Interface Proxy Price Determination

(Discussions ongoing regarding pricing methodologies with and without active Phase Angle Regulator controls)

e. Dispute Resolution

Parties to this effort will require access to pre-defined dispute resolution protocols to ensure matters 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.¹

There are also dispute resolution protocols in existing inter-control area operating agreements that could be of use in developing acceptable dispute resolution procedures²

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

¹ http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-76d90a48324a

² <http://www.nyiso.com/public/documents/regulatory/agreements.jsp>

agreement will need to appreciate that FERC jurisdiction only applies to MISO, PJM and NYISO.

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