Managing Congestion To Address Seams

A Proposal for Congestion Management Coordination

Submitted by
PJM-ISO
and the
Midwest ISO

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Revision History

DATE	EDITOR	VERSION	SUMMARY OF CHANGES
1/13/03	Tow Bowe	Draft 1	Initial draft
2/15/03	Tom Bowe	Draft 2	Added more detail for several topics
4/16/03	Andy Rodriquez	Final	See detailed change summary
4/28/03	Andy Rodriquez	Final-C01	Changes per PJM/MISO Review Team requests
5/9/03	Andy Rodriquez	Final-C02	Added 0%+counterflow change
5/16/03	Andy Rodriquez	Final-C03	Spelling correction, updated examples

Executive Summary

This is the final version of the PJM/MISO Congestion Management Proposal Whitepaper. This version differs significantly from the previous drafts, providing far more detail in the areas of Market Flow Calculation; NNL determination; the Tagging of Import and Export transactions; and flowgate determination. These additional details are the result of multiple meetings between the Operating Entities, as well as meetings with the NERC community and the industry's associated stakeholders. Some of these review meetings included:

- *Joint NERC CMS, IDCWG, and MISO/PJM Review Team (NERC ORS and RCWG) Meetings*
- *NERC Interchange Subcommittee Meeting*
- *MAIN Operating Committee Meetings*
- *ECAR CRC and Executive Board meetings*
- *MISO/PJM Open Stakeholders Meetings*

As PJM and MISO expand and implement their respective markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional) will interact to ensure that parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. PJM and MISO have actively worked with stakeholders in various forums in order to identify and address various concerns and issues. We have addressed these issues in this proposal. Responses to issues and questions raised by stakeholders are provided in Appendix H. While developed specifically to address the congestion management seams between the MISO and PJM, the concepts in this proposal are intended to provide a robust framework that may be used by other Operating Entities as they implement markets over large regions. The proposed solution will greatly enhance current IDC granularity by utilizing existing real-time applications to monitor and react to flowgates external to an Operating Entity's market footprint. PJM is a Market Based Operating Entity that plans to expand its area, and MISO is starting its Market Operations and is becoming a Market-Based Operating Entity. In brief, the proposal includes the following concepts:

- *Market-Based Operating Entities will agree to observe limits on an extensive list of coordinated external flowgates*
- *Like all control areas, Market-Based Operating Entities will have Network and Native Load (NNL) impacts upon those flowgates.*
- *Market-Based Operating Entities will determine these NNL impacts using the published analysis process, and constrain their operations to limit firm flows on the Coordinated Flowgates to no more than the calculated NNL contribution established in the analysis.*
- *In real-time, Market-Based Operating Entities will calculate and monitor when the projected and actual flows exceed the NNL limits established in the day-ahead process.*

- *Market-Based Operating Entities will post the NNL MW flow and additional non-firm economic market flow, as well as the actual and projected market flow, to the IDC for both internal and external Coordinated Flowgates.*
- *Market-Based Operating Entities will provide to the IDC detailed representation of their marginal units, so that the IDC can continue to effectively compute the effects of all tagged transactions regardless of the size of the market area. These tagged transactions will include transaction into the market, transactions out of the market, and tagged grandfathered transactions within the market.*
- *When there is a TLR 3a or higher called on a Coordinated Flowgate, and the Market-Based Operating Entity's actual/projected market flows exceed the NNL limits, Market-Based Operating Entities will redispatch in order to provide the required MW relief, per the IDC congestion management report.*
- *Entities may choose to enter into reciprocal coordination agreements with MISO and/or PJM that describe how ATC/AFC, NNL, and outage maintenance will be coordinated on a forward basis*
- *When there is a TLR 5a or 5b, all TPs will curtail or redispatch their respective systems to provide their shares of NNL reductions as directed by the IDC.*
- *Because the IDC will have the real-time/projected flows throughout the Market-Based Operating Entity's system (as represented by the impacts upon various Coordinated Flowgates), the effectiveness of the IDC will be greatly enhanced.*
- *The complete proposal will allow Market-Based Operating Entities to address the reliability aspects of congestion management seams issues between all parties whether the seams are between market to non-market operations or market to market operations.*

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Change Summary

- Developed Concept of Reciprocal Flowgates (sub-set of coordinated Flowgates) – (Section 6, Reciprocal Coordinated Flowgates)
- Created process to respect Reciprocal Flowgates in Day Ahead Unit Commitments, to ensure both Firm and Non-Firm flows do not overload flowgate (Section 6, Reciprocal Operations)
- Day Ahead Process for Reciprocal Flowgates creates two sub-sets of real-time Economic Dispatch. RTOs will treat Day Ahead ED as Bucket 6 and ED above this ED amount as Bucket 2. (Section 6, Coordination Process for Reciprocal Flowgates)
- Provided both Generic Examples and Specific Examples of Calculations and Processes (see Appendix E)
- List of the Coordinated Flowgates that PJM and MISO will need to respect (Appendix F)
- Included Appendix J which outlines the PJM/MISO Process to Coordinate AFC/ATC Process – a seams issue related to the congestion management seams issue
- Modified Study 3 to represent more accurate list of Coordinated Flowgates
- New Format and organization for the Whitepaper that has placed many of the PJM/MISO specific information in appendixes

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Section 1 - Introduction

As **Market-Based Operating Entities** expand and implement their respective markets, one of the primary seams issues that must be resolved is how congestion management will be implemented in coordination with other areas, both those that have similar markets and those that do not. PJM and the Midwest ISO (MISO) have actively worked with stakeholders in various forums in order to identify and address their respective concerns and issues regarding congestion management. We have addressed these issues in this proposal.

This is the third and final revision of the PJM/MISO Congestion Management Proposal. This revision differs significantly from the previous drafts, providing far more detail in the areas of Market Flow Calculation; Network Native Load (NNL) determination; the tagging of import and export transactions; and flowgate determination. These additional details are the result of multiple meetings between the Operating Entities, as well as meetings with the NERC community and the industry's associated stakeholders. Some of these review meetings included:

- Joint NERC CMS, IDCWG, and MISO/PJM Review Team (NERC ORS and RCWG) Meetings
- NERC Interchange Subcommittee Meeting
- MAIN Operating Committee Meetings
- ECAR CRC and Executive Board Meetings
- MISO/PJM Open Stakeholders Meetings

It is the intention of PJM and MISO to utilize the processes proposed within this document until both Operating Entities are operating within a joint and common market. It is further our intention to develop this proposal in a way that will allow other regional entities with similar concerns to utilize the concepts within this proposal to aid in the resolution of their own seams issues. PJM and MISO may recommend changes and improvements as operations continue and as each Operating Entity establishes full but independent markets.

Problem Definition

The Nature of Energy Flows

Energy flows are distinctly different from the manner in which the energy commodity is purchased, sold, and ultimately scheduled. In the current practice of "contract path" scheduling, schedules identify a source point for generation of energy, a series of wheeling agreements being utilized in to transport that energy, and a specific sink point where that energy is being consumed by a load. However, due to the electrical reality of the Eastern Interconnection, energy flows are much different than what is described within that schedule. This disconnect becomes of concern when there is a need to take actions on contract-path schedules to effect changes on the physical system (for example, the curtailment of schedules to relieve transmission constraints).

In the Eastern Interconnection, much of this concern has been addressed through the use of the NERC Transmission Loading Relief (TLR) process. Through this process, Reliability Coordinators utilize the *Interchange Distribution Calculator (IDC)* to determine appropriate actions to provide that relief. The IDC bases its calculations on the use of transaction tags: electronic documents that specify a source and a sink, which can be used to estimate real power flows through the use of a network model. In order to change flows, the IDC is given a particular constraint and a desired change in flows. The IDC returns back all source to sink transactions that contribute to that constraint and specify schedule changes to be made that will effect that change in flows.

In other parts of the Eastern Interconnection, however, the use of centralized economic dispatch results in a solution that does not focus on changing entire transactions (effectively redispatching through the use of imbalance energy), but rather redispatch itself. In this procedure, the party attempting to provide relief does not need to know that a balanced source to sink transaction should be adjusted; rather, they are aware of a net generation to load balance and the impacts of different generators on various constraints. Locational Marginal Pricing is a regional implementation of this practice.

Currently, these two practices are somewhat incompatible. However, due to the electrical characteristics of the Interconnection and geographic scope of the regions, this incompatibility has been of limited concern. However, regional market expansion has begun to draw attention to this philosophical disjoint, as the expansion itself exacerbates the negative effects of the incompatibility.

Granularity in the IDC

The IDC uses an approximation of the Interconnection to identify impacts on a particular transmission constraint that are caused by flows between Control Areas. This approximation allows for a Reliability Coordinator to identify tagged transactions with specific sources and sinks that are contributing to the constraint. While tagged transactions may specify sources and sinks in a very specific manner, the IDC in general cannot respect this detail, and instead consolidates the impacts of several generators and loads into a homogenous representation of the impacts of a single control area. This is referred to as the *granularity* of the IDC. Current granularity is typically defined to the Control Area level; finer granularity is present in certain special situations as deemed necessary by NERC.

Reduced Data and Granularity Coarseness

As centrally dispatched energy markets expand their footprint, two related changes occur with regard to the above process. In some cases, data previously sent to the IDC is no longer sent due to the fact that it is no longer tagged. In others, transactions remain tagged, but the increased market footprint results in an increase in granularity coarseness within the IDC.

In the first change, the transactions contained entirely within the market footprint are considered to be utilizing network service (even when the market spans multiple Control Areas, as is the case with the MISO). As such, there is no requirement for them to be tagged, and therefore, no requirement that they be sent to the IDC. This is of concern from a reliability perspective, as the IDC no longer has a large a pool of transactions from which to provide relief, although the energy flows may remain consistent with those prior to the market expansion. In other words, flows subject to TLR curtailment prior to the market expansion are no longer available for that process.

In the second change, the expansion of the footprint itself results in a corruption of the approximation utilized by the IDC. When a market region is relatively small (or isolated), the approximation of that region's impact on transmission constraints is acceptable; actions within the market footprint generally have a similar and consistent impact on all transmission facilities outside the footprint. However, when the market footprint expands significantly, the ability to utilize an electrically representative approximation becomes difficult. Impacts on external facilities can vary significantly depending on the dispatch of the resources within the market footprint. With regard to the IDC, this information is effectively lost within the expanded footprint, and results in an increase in the level of granularity coarseness, or a "loss of granularity."

Conclusion

The net effect of these changes is that reliability must be managed through different processes than those used before the market region's expansion. While relief can still be requested using the current process, both the ability to predict the ability of a transaction to provide that relief and the general pool of transactions available for curtailment are reduced. <u>This proposal offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the NERC IDC. This new congestion management process will ensure that reliability is only increased as markets expand by providing information and relief opportunities previously unavailable to the IDC</u>.

Proposal Scope and Limitations

Vision Statement

As Operating Entities expand and implement their various markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional TLR) will interact to ensure parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. For these entities, this proposal will offer a manner in which Market-Based Operating Entities can coordinate parallel flows with regions that have not yet implemented markets. Unlike the existing process, this proposal will provide more proactive management of transmission resources, more accurate information to Reliability Coordinators, and more candidates for providing relief when reliability is threatened due to transmission overload conditions.

Proposal Scope

While this proposal has been written specifically with the goal of coordinating seams between PJM and the Midwest ISO and their respective neighbors, this document may be beneficial to any Operating Entity facing similar seams issues related to congestion management. We offer this proposal as a way to achieve coordination between entities, and propose it as a potential option for any entities that wish to coordinate with each other.

Goals and Metrics

In preparing this document, we focused our solution on meeting the following goals and requirements:

a. Develop a congestion relief process whereby transmission overloads can be eliminated through a shared/effective reduction in flowgate or constraint usage by MISO, PJM, and other Reliability Coordinators.

b. Agree on a predefined set of flowgates or constraints to be considered by both organizations, and a process to maintain this set as necessary.

c. Determine the best way to calculate net flow due to one market's impact on a defined set of flowgates.

d. Develop reciprocal agreements that establish how each Operating Entity will consider its own flowgate or constraint usage as well as the usage of other Operating Entities when it determines the amount of flowgate or constraint capacity remaining.

e. Develop a procedure for managing congestion when flowgates are impacted by both tagged and non-tagged energy flow.

f. Develop a procedure for determining the priorities of untagged energy flows (created through parallel flows from the market).

g. Agree on steps to be taken by Operating Entities to unload a constraint on a shared basis.

h. Determine whether procedure(s) for managing congestion will differ based on where the flowgate is located (i.e., inside PJM, inside MISO, outside both PJM and MISO).

i. Confirm that the solution will be equitable for all parties, auditable, and independent.

Assumptions

The following assumptions were made as we considered the possible solutions for addressing these issues:

a. Point to Point schedules sinking in, sourcing from, or passing through a Market-Based Operating Entity will still be tagged.

b. The IDC is needed for at least the interim between the Interconnection's current state and full implementation of SMD.

c. The Market-Based Operating Entity can compute the impacts of the market dispatch on the flowgates as required by the IDC

d. The Market-Based Operating Entity's EMS has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch

e. The Reliability Coordinator of the area in which a flowgate exists will be responsible for monitoring the flowgate, determining any amount of relief needed, and entering the required relief in the IDC.

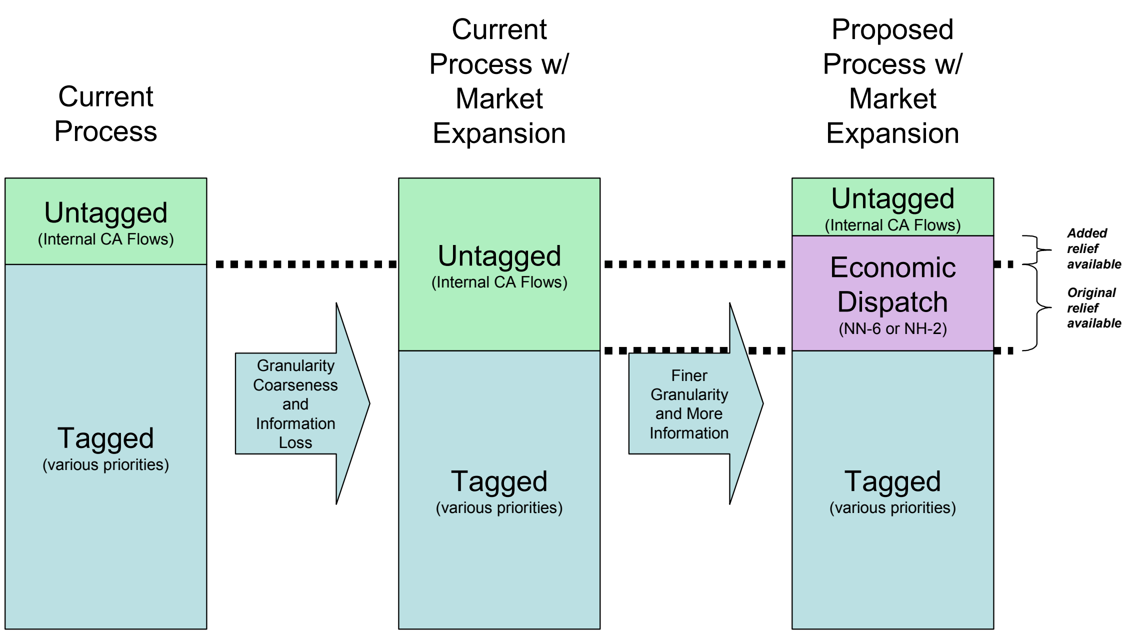
f. The IDC can be modified to accept the calculated values of the impact of real-time generation in order to determine which schedules require curtailment in conjunction with the required Market-Based Operating Entity's redispatch

g. The IDC will calculate the total amount of MW relief required by the Market-Based Operating Entity (schedule curtailments required plus the relief provided by redispatch).

Section 2 - Proposal Overview

Summary of Proposal

In order to coordinate congestion management, a bridge must be established that provides for comparable actions between regions. Without such a bridge, it is difficult, if not impossible, to ensure reliability and system coordination in an efficient manner. To effect this coordination of congestion management activities, we propose a methodology for determining both firm and non-firm flows resulting from Market-Based Operating entity dispatch on external parties flowgates.



Market Flows are defined as the flows generated from an operational entity's dispatch, and is equal to the sum of firm and non-firm flows. The firm components consist of the flows created both through serving Network Native Load (NNL) and by those schedules flowing on Firm transmission reservations (7-F). For the purposes of this proposal, both firm transmission and NNL schedules will be referred to as the **NNL** component of Market Flows, and are considered firm.

The remainders of Market Flows, therefore, are non-firm. When the values of these flows are known, they can be treated as equivalent to non-firm transmission service. As such, Reliability Coordinators can request Market-Based Operating entities provide relief under TLR based on these transmission priorities.

By applying the above philosophy to the problem of coordinating congestion management, we can determine not only the impacts of a Market-Based Operating entity's dispatch on a particular flowgate, we can also determine the appropriate firmness of those flows. This results in the ability to coordinate both proactive and reactive congestion management between operating entities in a way that respects the current TLR process, while still allowing for the flexibility of internal congestion management based on Locational Marginal Pricing.

There are two areas that must be defined in order for this proposal to work effectively:

- **Coordinated Flowgate Definition.** In order to ensure that impacts of dispatch are properly recognized, a list of flowgates must be developed around which congestion management may be effected and coordination can be established.
- **Congestion Management.** By coordinating congestion management efforts and enhancing the TLR process to recognize both untagged internal flows and data of finer granularity, we can ensure that when TLR is called, the appropriate non-firm flows are reduced before firm flows. This will result in a reduction of TLR 5 events, as more relief will be available in TLR 3 to mitigate a constraint. We will accomplish this through the calculation of flows due to Economic Dispatch, as well as by providing Marginal Unit information to aid in Interchange transaction management.

The remaining portions of this document discuss each of these areas in detail.

Section 3 - Flowgate Definition

Coordinated Flowgates

The Market-Based Operating Entity will conduct sensitivity studies to determine which external flowgates (outside the Market-Based Operating Entity's footprint) are significantly impacted by the market flows of the market–based Operating Entity's control zones (currently the Control Areas that exist today in the IDC). The Market-Based Operating Entity will perform the following 4 studies to determine which external flowgates the Market-Based Operating Entity will monitor and help control. An external flowgate selected by one of these studies will be considered a **Coordinated Flowgate (CF)**.

A Market-Based Operating Entity may also specify internal flowgates to be Coordinated Flowgates. For flowgates on which the Market-Based Operating Entity expects to utilize the TLR process to protect system reliability, such specification is required. For a list of Coordinated Flowgates currently under evaluation for Coordinated Flowgate status, please see Appendix F.

Coordinated Flowgates are defined for two primary functions: to establish criteria for which coordination agreements can be written, and to provide information to Reliability Coordinators to aid in congestion management activities. A Market-Based Operating Entity working under this proposal will develop a list of Coordinated Flowgates for use with the IDC. They may also utilize those Coordinated Flowgates to establish reciprocal coordination agreements with neighboring entities.

PJM and MISO will work with NERC and the TLR history to further validate this list of proposed flowgates. PJM and MISO will also implement the rulings of the Michigan/Wisconsin Hold Harmless proceedings. This list will be reviewed by various Regional and NERC Committees (ORS/OC) to ensure its appropriateness. Use of a 5% threshold in the studies may not capture all flowgates that experience a significant impact due to market operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC implements the use of a lower threshold in the TLR process.

Study 1) – IDC Base Case

(no transmission outages – using the IDC tool)

The IDC can provide a list of flowgates for any user-specified Control Area whose GLDF (Generator to Load Distribution Factor (NNL)) impact is 5% or greater. The Market-Based Operating Entity will use the IDC capabilities to develop a preliminary set of flowgates. This list will contain external flowgates that are impacted by 5% or greater by the current Control Areas that will be joining the Market-Based Operating Entity as Market control zones/areas. Using the present control area representation in the IDC (i.e., pre-Operating Entity expansion), if any one generator has a GLDF (Generator to Load Distribution Factor) greater than 5% as determined by the IDC, this flowgate will be considered a Coordinated Flowgate.

As an example, consider the PTDF flowgate #3301:

Flowgate #3301 - Tazewell-Mason 138 kV line

This flowgate is located in the Central Illinois Light Company control area, which is joining the MISO Operating Entity. The GLDFs obtained from the IDC indicate that there are two units in the Com-Ed control area that have a GLDF greater than 5%. Com-Ed is joining the PJM Operating Entity.

Although there are about 150 generators in the Com-Ed area that do not have a GLDF greater than 5% (and some units which have a negative GLDF), the fact that there is at least one generator with a GLDF greater than 5% qualifies this flowgate for inclusion in the PJM Operating Entity list of Coordinated Flowgates that PJM will respect.

Study 2) – IDC PSS/E Base Case

(no transmission outages – offline study)

In order to confirm the IDC analysis, and to provide a better confidence that the Market-Based Operating Entity has effectively captured the subset of flowgates upon which its generators have a significant impact, a MUST power-flow study will be conducted. The Market-Based Operating Entity will perform off-line studies (using the IDC PSS/E base case) to confirm the IDC analysis.

Study 3) – IDC PSS/E Base Case

(transmission outage - offline study)

In order to determine outage conditions (if any) that may cause the Market-Based Operating Entity's control zones/areas to have a significant impact on external flowgates, the Market-Based Operating Entity will perform 2nd contingency (n-2) analysis, including both internal and external outages. This study will be performed offline using MUST powerflow capabilities. If any additional flowgates are found using this method, AND they represent a 3% or greater impact when reexamined under Study 1 or 4, they will be added to the list of Coordinated Flowgates.

Study 4) – Control Area to Control Area

For those situations where one or more Control Areas are being incorporated into a market footprint, there will be a flowgate analysis performed to determine which flowgates impacted by those Control Areas will be included in the list of Coordinated flowgates. The Market-Based Operating Entity will analyze transactions between each CA and the existing market, as well as between each CA/CA permutation (if more than one CA is moving into the market). This study will use Transfer Distribution Factors (TDFs) from the IDC. Flowgates that are impacted by greater than 5% as determined by the IDC will be considered a Coordinated Flowgate.

Disputed Flowgates

If a Reliability Coordinator (RC) believes that a Market-Based Operating Entity's flows have a significant impact on one of their flowgates, but that flowgate was not included in the Coordinated Flowgate list, the following process will be followed by the involved parties.

The RC conducts studies to determine the conditions under which an Operating Entity's market flows would have a significant impact on the flowgate in question. The RC then submits these studies to the Operating Entities implementing this proposal. The RC'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 Operating Entities will review the studies and determine if they appear to support the request of the RC. If they do, the flowgate will be added to the list of Coordinated Flowgates.

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

Dynamic Creation of Flowgates

For temporary Flowgates developed "on the fly," studies 1, 2, and 4 as described above will be performed by the Operating Entity. The intent of this process is to complete all of this analysis and changes in 60 minutes or less (as close to real-time as possible). If the temporary flowgate meets the criteria as specified, the Operating Entity will incorporate the new flowgate into the monitoring process and the Operating Entity will calculate both a market flow and NNL value as soon as possible.

The Operating Entity will provide these values to the IDC in the same manner as market flows and NNL values are provided to the IDC for all other Coordinated Flowgates. Off-line load flows required to perform the analysis and determine any values needed will be saved on a daily basis to expedite the required calculation.

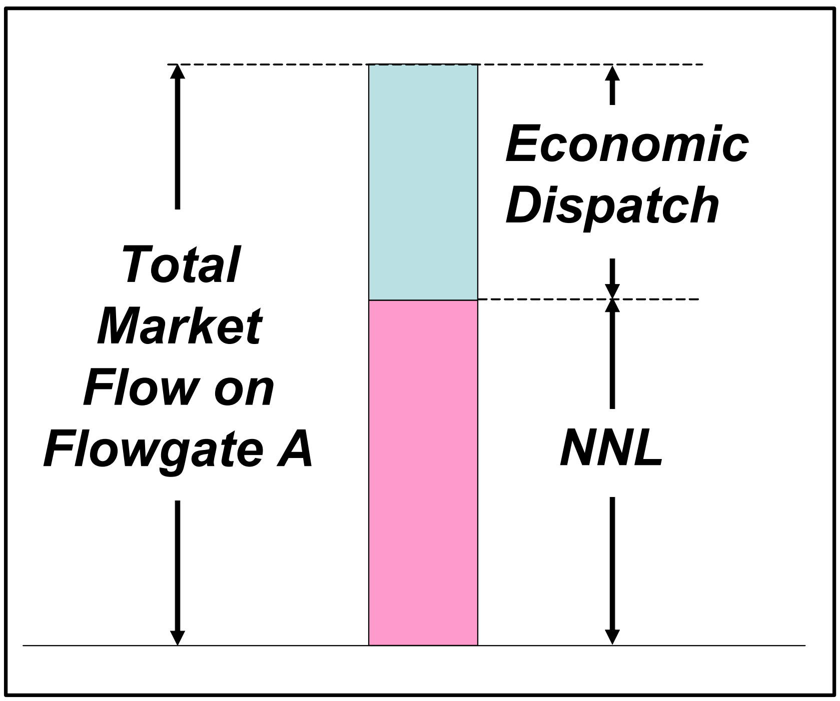
As is presently the case for any temporary flowgate, the IDC will identify contracts sourcing out of or sinking into the Operating Entity that exceed the IDC threshold level and are therefore subject to curtailment. It is expected that discussions between the Reliability Coordinator creating the temporary flowgate and the Market-Based Operating Entity will occur to ensure that any contributing circumstances requiring the temporary flowgate are understood and known.

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 Operating Entity's will coordinate respective actions to provide immediate relief until final review

The present functionality of PJM's and MISO's real-time Security Analysis programs allows for the creation and activation of new contingencies or flowgates in real-time within a matter of minutes. Data set builds or uploads are not necessary to add a new contingency or flowgate to these real-time monitoring and control applications. With the flowgate now included in the real-time system, PJM and MISO can then redispatch effective internal generation to provide the required/requested relief exactly as will be done for all other Coordinated Flowgates.

Section 4 - Flow Calculations: Market Flow, NNL, and Economic Dispatch

When a Market-Based Operating Entity's dispatch creates flows on a Coordinated Flowgate, those flows can be quantified and considered the **Market Flow.** Market flow is then further designated into two components: **NNL Flow,** which is energy flow related to contributions from the Network Native Load serving aspects of the dispatch, and **Economic Dispatch (ED) Flow,** which is energy flow related to the Market-Based Operating Entity's market operations. These distinctions are important, as the NNL Flows are considered firm, while the Economic Dispatch flows are not.



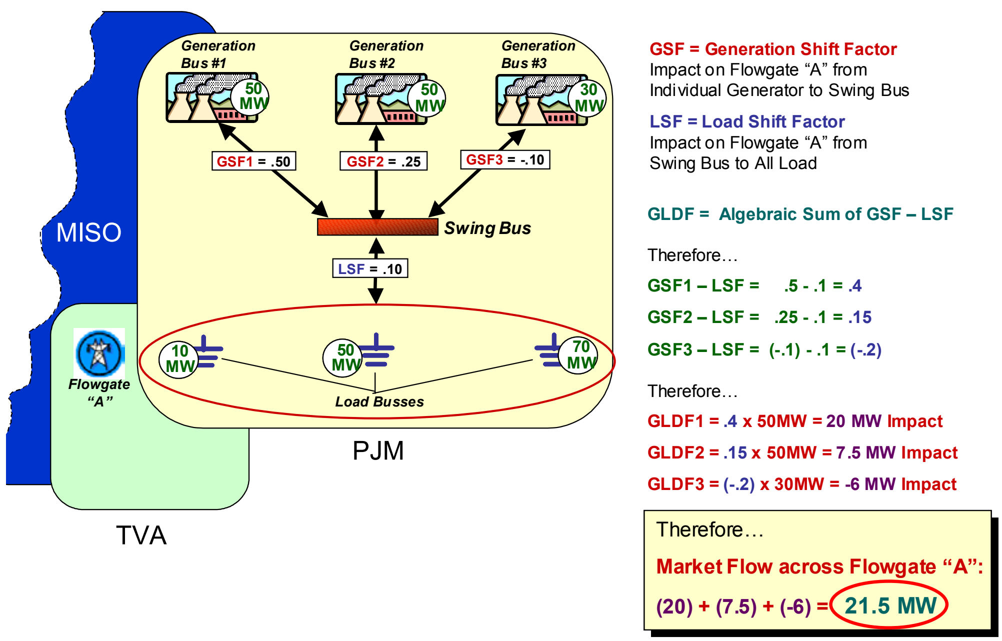
Each Market-Based Operating Entity will calculate their actual real-time and projected Market Flows, as well as their NNL Flows, on each Coordinated Flowgate. These two values will allow the Market-Based Operating Entity to determine the Economic Dispatch (ED) Flows created by the markets operations. The following sections outline how these flows will be computed.

Market Flow Determination

The determination of Market Flows builds on the "Per Generator" methodologies that were developed by the NERC Parallel Flow Task Force. The "Per Generator Method Without Counter Flow" was presented to and approved by both the NERC Security

Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC). [1] This methodology is presently used in the IDC to determine NNL contributions.
Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (e.g. the terminal bus of each generator) while the LSFs are defined as a general scaling of the market area's load. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific flowgate is the product of the generator's GLDF multiplied by the actual output (in megawatts) of that generator. The total Market Flow on a specific flowgate is the sum of the Market Flow contributions of each generator within the market area.



The Market Flow calculation differs from the Per Generator method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the

[1] "Parallel Flow Calculation Procedure Reference Document," NERC Operating Manual. 11 Feb, 2003. <http://www.nerc.com/~oc/opermanl.html>

sum of the maximum generating capacity at a bus is greater than 20 MW. The Market Flow calculations will use all flows, including counterflows, down to 0% with no threshold. NERC may need to modify the IDC to model counterflows to ensure comparability.

- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the Market Flow calculation evolves into a methodology very similar the "Per Generator Method With Counterflow," while providing a granularity on the order of the most granular method developed by the IDC Granularity Task Force. Counterflows are required for this proposal to ensure a Market-Based Operating Entity can effectively select the most effective generation pattern to control the flows on both internal and external constraints. Without using counterflows, such an entity would not be able to accurately calculate the responses that a Reliability Coordinator requires. Under this proposal, the use of real-time values in concert with the market Flow calculation effectively implements the most accurate and detailed method of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force

Units assigned to serve a market area's load do not need to reside within the market area's footprint to be considered in the Market Flow calculation. However, units outside of the market area will not be considered when those units will have tags associated with their transfers.

Additionally, there may be situations where the participation of a generator in the market may be less than 100% (e.g., a unit jointly owned in which not all of the owners are participating in the market). Such situations will need to be recognized and accounted for in the market's operations.

Finally, imports into or exports out of the market area, and tagged grandfathered transactions within the market area, must be properly accounted for in the determination of Market Flows. When the actual generation of the market area exceeds the total load of that area, the market area is exporting energy. These exports are tagged transactions that must be accounted for in the Market Flow calculation. This will be accomplished within the calculation by including a new term that offsets the MW output of the marginal unit(s) by the amount of the net market export. This ensures that the Market Flow calculation is measuring only the effect of internal generation serving internal load.

When the actual generation of the market area is less than the total load of the market area, that area is importing energy. These imports are tagged transactions that are also not to be included in the determination of Market Flows, as "Market Flows" are a measure of internal generation serving internal load. The processes currently within IDC will address the counting of these transactions.

Below is a summary of the calculations discussed above.

For a specified flowgate, the Market Flow impact of a market area is given as:

Total "Market Flow" = ∑ ("Market Flow" contribution of each unit in the LMP area)

where,

"Market Flow" contribution of each unit in the LMP area =

(GLDF) (Real-Time generator output) (Participation Percent/100)

and,

GLDF is the Generator to Load Distribution Factor

Real-Time generator output* is the present MW level of the generator

Participation Percent is the share of the unit participating in the LMP area's market

(* if the RTO is a net exporter at the time of the calculation, the output level of the marginal unit(s) has been reduced by this export value)

The real-time and projected "Market Flows" will be calculated on-line utilizing the LMP area's state estimator model and solution. Tthis is the same solution presently used to determine real-time LMPs as well as providing on-line reliability assessment and the periodicity of the Market Flow calculation will be on the same order. Inputs to the state estimator solution include the topology of the transmission system and actual analog values (e.g., line flows, transformer flows, etc…). This information is provided to the state estimator automatically via SCADA systems such as NERC's ISN link.

Using an on-line state estimator model to calculate "Market Flows" provides a more accurate assessment than using an off-line representation for a number of reasons. The calculation incorporates a significant amount of real-time data, including:

- **Actual real-time and projected generator output.** Off-line models often assume an output level based on a nominal value (such as unit maximum capability), but there is no guarantee that the unit will be operating at that assumed level, or even on-line. Off-line models may not reflect the impact of pumped-storage units when in pumping mode; these units may be represented as a generator even when pumping. A real-time calculation explicitly represents the actual operating modes of these units.
- **Actual real-time bus loads.** Off-line assessments may not be able to accurately account for changes in load diversity. Off-line models are often based on seasonal winter and summer peak load base cases. While representative of these peak periods, these cases may not reflect the load diversity that exists during off-peak and shoulder hours as well as off-peak and shoulder months. A real-time calculation explicitly accounts for load diversity. Off-line assessments may also reflect load reduction programs that are only in effect during peak periods.
- **Actual real-time breaker status.** Off-line assessments are often bus models, where individual circuit breakers are not represented. On-line models are typically node models where switching devices are explicitly represented. This allows for the real-time calculation to automatically account for split bus conditions and unusual topology conditions due to circuit breaker outages.

Additionally, the calculation rate of the on-line assessment is much quicker and accurate than an off-line assessment, as the on-line assessment immediately incorporates changes in system topology and generators. Facility trippings and outages are automatically incorporated into the real-time assessment.

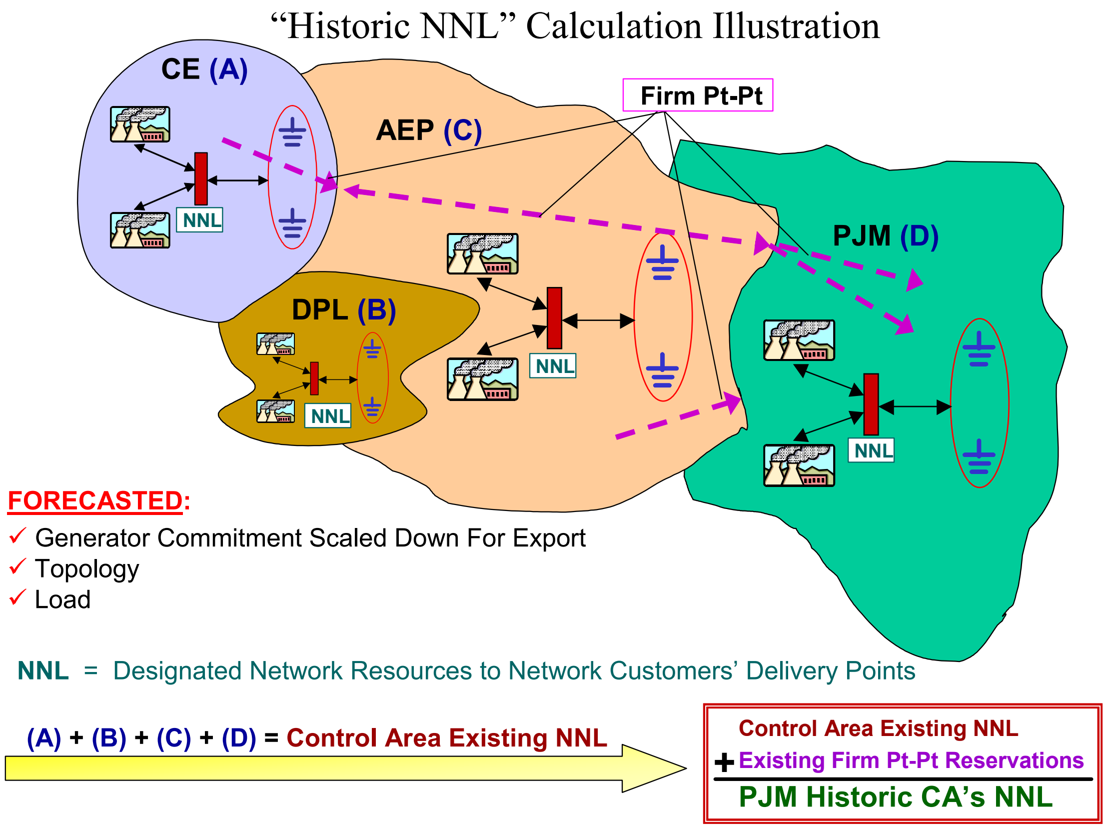
In order to provide reliable and consistent flow calculations, entities utilizing this process as the basis for coordination must ensure that the modeling data and assumptions used in the calculation process are consistent. PJM and MISO will coordinate models to ensure similar computations and analysis. PJM and MISO will each utilize real-time ICCP and ISN data for observable areas in each of their respective state estimator models and will utilize NERC data for areas outside the observable areas to ensure their models stay synchronized with each other and the NERC IDC.

NNL Flow Determination Overview

NNL Flows represent the sum of designated network resources serving designated network loads within a particular market area, as well as any firm point-to-point transactions. 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 NNL Flows can be determined based on expected usage and the allocation of flowgate capacity.

An entity can determine firm network service flows on a particular flowgate using the same process as utilized by the IDC. This process is summarized below:

1. Utilize a 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 areas load to a specific swing bus with respect to that flowgate.
3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for generator with respect to that flowgate.
4. Multiply the expected output used to serve native load from generator by the appropriate GLDF to determine that generators flow on the flowgate.
5. Sum these individual contributions to create the firm network service impact on the flowgate.



Additionally, NNL Flows incorporate the Firm Point-to-Point flows as well. Similar to the network service calculation above, to calculate each firm PTP transactions impact on the flowgate, utilize the following process:

1. Utilize a base case to determine the Generation Shift Factor for the source Control Area with respect to a specific flowgate.
2. Utilize the same base case to determine the Generation Shift Factor for the sink Control Area with respect to that flowgate.
3. Utilize superposition to calculate the Transmission Distribution Factor (TDF) for that source to sink pair with respect to that flowgate.
4. Multiply the transactions energy transfer by the TDF to determine that transactions flow on the flowgate.

Summing each of these impacts will provide the firm point-to-point service impact on the flowgate.

Combining the firm point-to-point service impact with the firm network service impact will provide the NNL Flow on the flowgate.

PJM and MISO will utilize the MMWG Seasonal Base cases at the reference base case for these calculations.

Calculating Historic NNL Flows

As a starting point for identifying NNL Limits, an understanding must be developed of what NNL flows would be in the existing Control Area structure. In other words, the NNL values that would have occurred if all control areas maintained their current configuration and continued to serve their native load with their generation can be identified. This flow is referred to as **Historic NNL.**

Market-Based Operating Entities will need to develop specific processes for ensuring reasonably accurate data is utilized in this process.

PJM and MISO have agreed to several rules for determining NNL. These rules are based on the rules used by the IDC, and can be found in later in this Section.

Determining the NNL Limit

Given the Historic NNL value, market-based operating entities can assume this to be their **NNL Limit.** This limit defines the maximum value of their Market Flows that can considered as NNL (and therefore firm). This NNL Limit is established initially when the Historic NNL is calculated by the market-based operating entities..

However, as system conditions and topology change, the NNL limit may change. When the calculations used to determine Historic NNL are recalculated using more current data, the resultant NNL estimated values may differ from those originally calculated.

Two days prior to real time, another calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of NNL. If the new values result in a change to the NNL Limit for a particular hour, that change is used in place of the Historic Limit for that hour.

Should additional firm capacity become available on the flowgate (based on changes in topology, margins, or other means), it should be allocated to the entities impacting the flowgate using the historic ratios determined with peak loads.. For example:

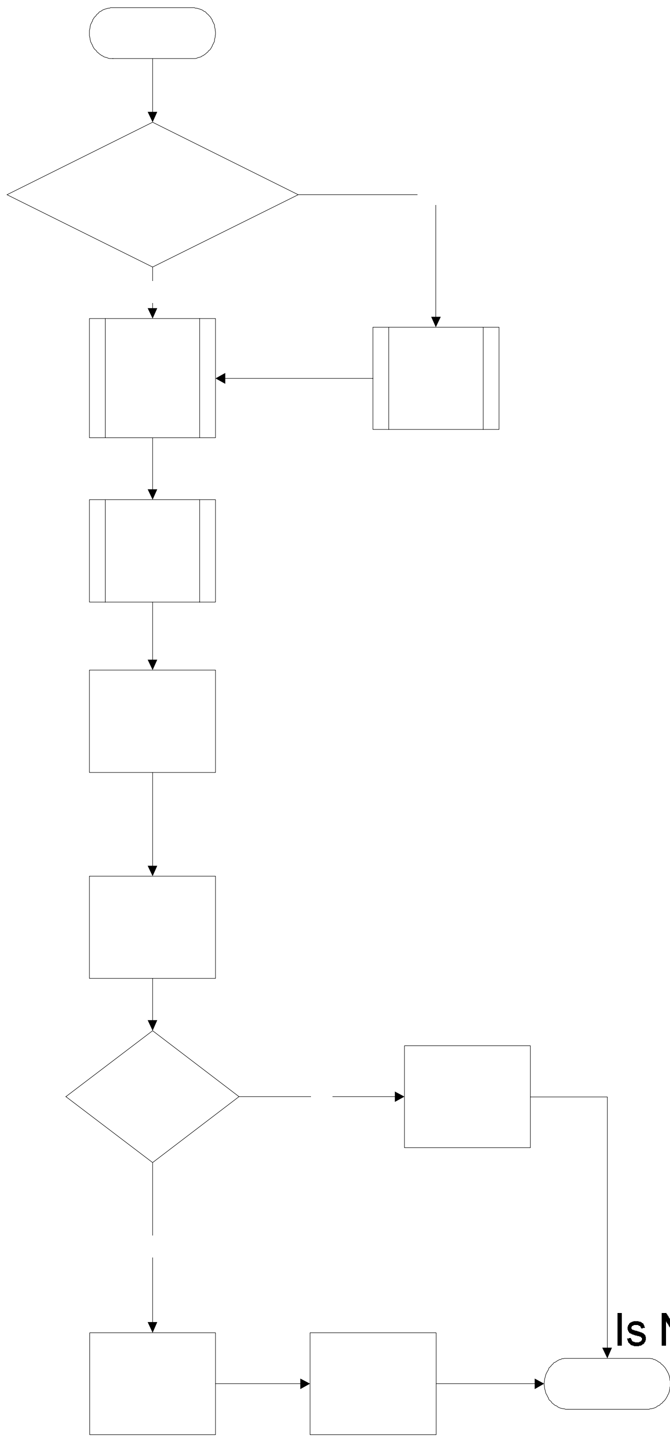
Entity A's Calculated Historic NNL: 20MW
Entity B's Calculated Historic NNL: 80MW
Initial NNL Limit for A: 20MW
Initial NNL Limit for B: 80MW
Entity A's Calculated NNL for HE20, two days prior: 16MW
Entity B's Calculated NNL for HE20, two days prior: 64MW
Total Calculated NNL Flows, two days prior: 80MW

AFC Calculations performed – AFC = 15MW

A's allocation = 15MW * (20MW/(20MW+80MW)) = 3MW
B's allocation = 15MW * (80MW/(20MW+80MW)) = 12MW
A's new NNL Limit for HE20: 19MW
B's new NNL Limit for HE20: 76MW

Note that the allocations are based on the previously calculated Historic NNL values.

The process below illustrates the above concepts:



PJM and MISO have agreed to a methodology for distributing any increase to the NNL Limit based on the Historical NNL values. See Section 6 for more information.

Recalculation of Initial Historic NNL Values and Ratios

The initial Historic NNL calculated values and resulting allocation ratios would be recalculated once per year. This recalculation will utilize the same firm point-to-point reservations that were used in the initial Historic NNL calculation. The same firm point-to-point reservations are used so that market-operating entities that have their firm point-to-point internalized, grant fewer internal firm service reservations, or have their original firm reservations end, because of their market operations, will retain at least the same level of firm point-to-point as in the initial Historic NNL calculation. Therefore, the firm point-to-point component of the Historic NNL will be frozen at the initially calculated level for both market and non-market entities.

However, the Designated Resource to Customer load portion of the Historic NNL calculation will be updated in the recalculation of Historic NNL utilizing any new Designated Resources, updated customer loads, and new transmission facilities. The original Historic Control Areas will be retained for the recalculation of Historic NNL. New Designated Resources will be included in the recalculation to the extent these new Designated Resources have been arranged for the exclusive use of load within the Historic Control Areas.

Any new Control Areas that are added to the NNL calculation process for either PJM, MISO, or another Operating Entity, will use firm point-to-point reservations from the initial Historic NNL calculation date to establish their firm point-to-point component of the Historic NNL.

MISO and PJM will utilize this recalculation process annually until it is replaced by another process. It is anticipated that an enhanced, market-to-market, process will be developed to replace the Historic NNL calculation process. The enhanced process may use a simultaneous deliverability type analysis rather than the historic NNL calculation process. MISO and PJM will update their respective Reliability Plans incorporating the new process and have them approved by NERC before the new process to quantify NNL is implemented.

NNL Calculation Rules

Historic NNL and NNL Limits will be calculated based on certain criteria and rules. The calculation will include the effects of both firm network service and firm point-to-point transmission service. The process will be similar to that of the IDC (but utilizing reservations instead of schedules, given the two-day lead time, as well as impacts down to 0% and counterflows). The following points form the basis for the calculation.

Firm Network Service

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. All impacts on the flowgate will be considered, including counterflows and impacts of less than 5%.
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. If a generator or a portion of a generator is used to make off-system sales that have an OASIS reservation, that generator or portion of a generator should be excluded from the generation-to-load calculation.
6. Generators that will be off-line during the calculated period will not be included in the generation-to-load calculation for that period.
7. CA net interchange will be computed by summing all firm PTP 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).
8. If the net interchange is negative, the period load is reduced by the net interchange. The maximum real power (PMAX) of all designated network resources included in the generation-to-load calculation are summed. If the summation of the PMAX exceeds the reduced load, the PMAX of each generator is decreased by a proportional amount. If the summation of PMAX is less than the reduced load, there is no decrease in the PMAX of each generator.
9. If the net interchange is positive, the period load is not adjusted for net interchange. The PMAX of a designated network resources included in the generation-to-load calculation are summed. If the summation of the PMAX exceeds the load, the PMAX of each generator is decreased by a proportional amount. If the summation of the PMAX is less than the load, there is no decrease in the PMAX of each generator.
10. 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.
11. PMAX of the generators should be net generation (excluding the plant auxiliaries) and the CA load should not include plant auxiliaries.
12. The portion of JOUs that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

Firm Point-to-Point Transactions

1. Firm PTP transmission service and designated network resources that have an OASIS reservation are included in the calculation.
2. A date will be selected as a freeze date. This means all confirmed reservations that have been made as of that date extending for some time into the future will be considered. Confirmed reservations received after the freeze date will not be considered.

3. A potential for duplicate reservations exists if a transaction was made on individual CA tariffs (not a regional tariff) and both parties to the transaction (source and sink) are Reciprocal Entities. In this case, each Reciprocal Entity will receive 50% of the transaction impact.
4. To the extent a partial path reservation is known to exist, it will have 100% of its impacts considered on Coordinated Flowgates owned by the party that sold the partial path service and 0% of its impacts considered on other Coordinated Flowgates.
5. Because reservations that are totally within the footprint of the regional tariff do not have duplicate reservations, these reservations will have the full impact considered even though both parties to the transaction (source and sink) are within the boundaries of the regional tariff and could be considered Reciprocal Entities.

6. Similar to the firm network service calculation, the firm point-to-point service calculation:
    - All reservations will be considered (including counterflowing and those with less than 5% impact)
    - Will base response factors on the topology of the system for the period under consideration.
    - In general, a generation-to-load calculation will not be made where a reservation exists.

Section 5 - Congestion Management

Once there has been an establishment of the NNL amount that is possible given historical NNL flows, we can move into operations and utilize that data in a manner that relates to real time energy flows.

Calculating Market Flows

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

Providing Data for Reliability Analysis

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

- Market Flows for all Coordinated Flowgates
- NNL Flows for all Coordinated Flowgates
- Economic Dispatch Flows for all Coordinated Flowgates

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 as the result of firm service on the various Coordinated Flowgates. When NNL Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual NNL Limit (used in TLR5) will be set equal to Market Flow.

Additionally, every hour the Market-Based Operating Entity will submit to the Reliability Authority 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 regions 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 Authority 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 Operating Entity executes a Day-Ahead Unit commitment for all of the generators throughout the Operating Entity footprint. PJM's and MISO's day ahead unit commitment uses a network analysis model that mirrors the real-time model found within their state estimators. As such, the day ahead commitment respects facility limits and forecasted system constraints.

Using the derived NNL value, the Operating Entity may enter this NNL value as a facility limit for the respective flowgate. PJM and MISO will use this NNL limit to restrict unit scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a flowgate.

If bound, the Day Ahead Unit commitment will not permit flows to exceed this NNL value as it selects units for this commitment.

Real-time Operations Process

Operating Entity Capabilities

PJM's and MISO's real-time EMSs 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, PJM, MISO, and OATI will be continually working to ensure model synchronization. PJM and MISO will also initiate similar coordination whenever the IDC model is updated. The data PJM and MISO will utilize in its model will be either over ICCP links or over the NERC ISN.

The PJM and MISO state estimators and the Unit Dispatch Systems (UDS) will utilize all of these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows (i.e., total Market Flows, Economic Dispatch, and NNL Limit) on all of the Coordinated Flowgates. Using real-time modeling, the PJM and MISO 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 very static SDX data that models generators as either at full output or off. In contrast, PJM's and MISO's calculations of system flows will utilize each unit's actual output, updated every at least every 15 minutes on an established schedule.

Operating Entity Real-time Actions

Operating Entities will have the list of third party/external Coordinated Flowgates modeled as monitored facilities in its EMS. The limits an Operating entity will use for these third party flowgates will be the NNL values determined by the NNL Calculations.

The Operating Entity will upload the real-time and projected flows, as well as the delta of the NNL and actual flows on these flowgates, to the IDC (every 15 minutes – as requested by the NERC IDCWG and OATI). When the real time actual or projected flows exceed these NNL values on a flowgate <u>and</u> the Reliability Coordinator who has responsibility for that flowgate has declared a TLR 3a or higher, the 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 Operating Entity could be required to redispatch to the full amount of economic dispatch over the NNL Limit.

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 Operating Entity will make any transaction curtailments as specified by the NERC IDC.

PJM's and MISO's redispatch/relief 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 RC calling the TLR will be able to see the relief provided on the flowgate as the Operating Entity continues to upload their contributions to the real-time flows on this flowgate.

Section 6 - Reciprocal Operations

PJM and the Midwest ISO intend to be the first entities to implement this plan. Further, PJM and MISO will augment the plan with the creation of reciprocal coordination agreements. These agreements will go beyond the previously discussed processes to ensure better coordination between entities. The sections following provide detail regarding PJM's and MISO's agreed to calculation procedures and reciprocal coordination practices.

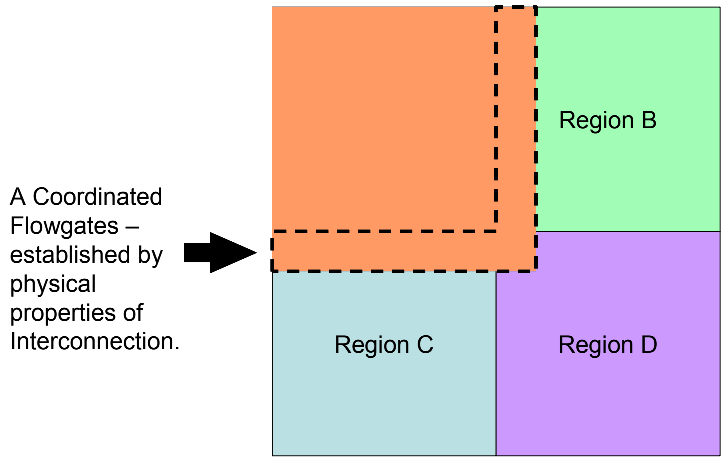
Reciprocated Coordinated Flowgates

In order to coordinate congestion management on a proactive basis, Operating Entities may agree to respect each others flowgate limitations during the determination of AFC/ATC and the calculation of firmness (Firm, Non-Firm Network, Non-Firm Hourly) during real-time operations. Entities agreeing to coordinate this forward-looking management of flowgate capacity are **Reciprocal Entities.** The Coordinated Flowgates used in that process are **Reciprocated Coordinated Flowgates (RCFs).**

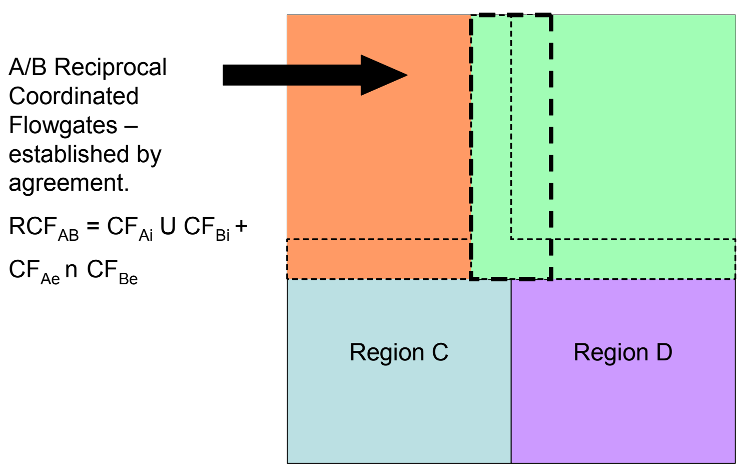
The Relationship Between CFs and RCFs

Coordinated flowgates are associated with a specific entity's operation sphere of influence. Reciprocal Coordinated Flowgates are associated with the implementation of a reciprocal coordination agreement between two entities.

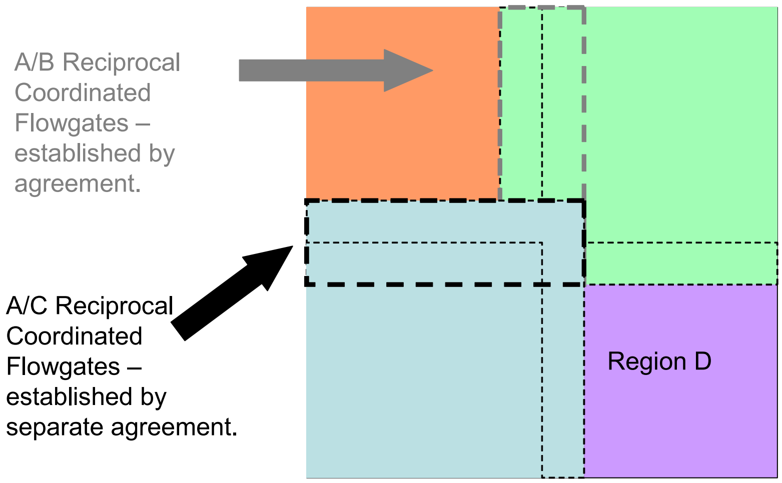
In the example below, there are four entities. The translucent red area represents the set of Coordinated Flowgates for market area A. Note that each area has it's own potential set of Coordinated Flowgates. As indicated, this set of Coordinated Flowgates is based only on the area's impact on flowgates, not on coordination agreements. Market Area A will report information to the IDC for these flowgates to aid in curtailment procedures, but is not required to engage in any other coordination efforts (e.g., AFC Coordination, NNL allocation, etc…).



In the next example, note that both A and B have established their set of Coordinated Flowgates. A subset of the union of these sets of flowgates establishes a baseline where reciprocal coordination can occur. This subset will include the union of all Coordinated Flowgates internal to the reciprocal entities and the intersection of all Coordinated Flowgates external to the reciprocal entities. If A and B choose to execute a reciprocal coordination agreement, the area bounded by the heavy line will become the set of Reciprocal Coordinated Flowgates. There are no coordination agreements with C and D.



If C wished to enter into a reciprocal coordination agreement with A, C would have to first establish their own set of Coordinated Flowgates. Following this, they would identify the set of Reciprocal Coordinated Flowgates, then agree to coordinate operations based on the flowgates contained in that that set



In the last example, we illustrate a fully coordinated set of entities and the agreements that would need to be established with each entity respecting each others impacted flowgates.

Full Reciprocal Coordination. Reciprocal Coordination areas as follows:

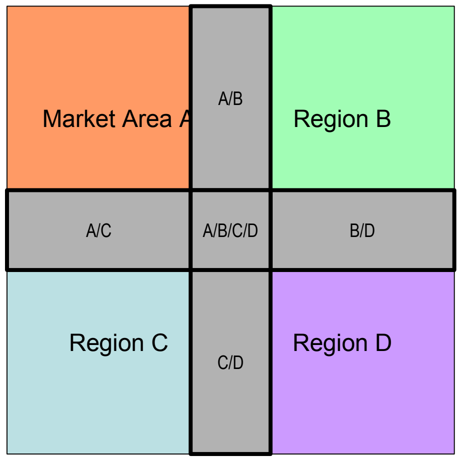
A/B (2 party)

A/C (2 party)

A/B/C/D (4 party)

B/D (2 party)

C/D (2 party)



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Coordination Process for Reciprocal Flowgates

The Reciprocal Entities will establish and finalize the process and timing for coordinating the ATC/AFC calculations and NNL calculations/allocations. Further, the process will quantify and limit Priority 6 – NN service on the RCFs, as well as determine priority 2-NH service. The following provides a blueprint for the process. It is expected each the Reciprocal Entities will require a Tariff changing and filing to FERC in order to implement this process. All reciprocal entities NLL will be calculated on the same basis.

Six Months prior:

ATC/AFC/NNL calculations will be performed to determine committed long-term firm and network service usage of RCFs and to allocate remaining capability. NNL calculations will be conducted per the NNL Calculation section of this paper. This long-term firm and network service usage of RCFs will be Reciprocal Entities Base Usage. Allocation of remaining capability will be based on ratio of each Reciprocal Entity's Base Usage to total Reciprocal Entities Base Usages. Each Reciprocal Entities will grant additional service while remaining within their allocation. Monthly values for the next 13 months will be calculated.

One Month prior:

ATC/AFC/NNL calculation will be refreshed using Reciprocal entities Base Usages considered at Six Months prior to determine if any additional firm capabilities may be released. Latest forecasts for system conditions will be utilized in this calculation. Each party may utilize any additional firm capabilities (based upon Six Months prior allocation ratio) determined to exist beyond what was allocated Six Months prior. Weekly values will be calculated for the next four weeks and replace monthly values for that time frame.

One Week prior:

ATC/AFC/NNL calculation will be refreshed using Reciprocal Entities' Base Usages considered at Six Months prior to determine if any additional firm capabilities may be released. Latest forecasts for system conditions will be utilized in this calculation. Each party may utilize any additional firm capabilities (based upon Six Months prior allocation ratio) determined to exist beyond what was allocated Six Months prior. Daily values will be calculated for the next seven days and replace weekly values for that time frame.

Two days prior:

ATC/AFC/NNL calculation will be refreshed using Reciprocal Entities' Base Usages considered at Six Months prior to determine if any additional firm capabilities may be released. Latest forecasts for system conditions will be utilized in this calculation. Each party may utilize any additional firm capabilities (based upon Six Months prior allocation ratio) determined to exist beyond what was allocated Six Months prior. Hourly values will be calculated for the next 24 hours daily values for that time frame.

This is the final NNL allocation. Base usage plus final allocation will equal total firm allocation, and be known as NNL Limit for the flowgate. Parties may grant additional firm reservations and/or commit units based up their Total Firm NNL/AFC/ATC allocation. Parities must plan to keep total firm flows within their allocation. This calculation will define the hourly historic NNL Limit values for the actual operating day.

Day Ahead

Reciprocal entities quantify committed and available Non-Firm Priority-6 level service while respecting limits on RCFs incorporating Firm schedules, Firm Allocated NNL, Non-Firm Priority-6 schedules, Reciprocal Market(s) expected dispatch, topology, loads, & net control zone interchanges. Allocation of total Non-Firm Priority 6-NN level service on RCFs is allocated among the Reciprocal entities utilizing calculated NNL allocation ratios for those flowgates. Each Reciprocal entity will receive its ratio share of the Non-Firm Priority-6 NN level service to use for economic dispatch and point-to-point service.

The Operating Entity then executes a Day-Ahead Unit commitment for all of the generators throughout the Operating Entity footprint, respecting facility limits and forecasted system constraints. PJM and MISO will use the NNL limit calculated above to restrict unit scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a flowgate. If so bound, the Day Ahead Unit commitment will not permit flows to exceed this NNL value as it selects units for this commitment.

Some of the reciprocal entities may have already committed some, all, or more than their allocation when this calculation is performed. For this reason, the Reciprocal entities will analyze the timing of the calculation and allocation of Non-Firm Priority 6-NN level service to determine if the calculation should be earlier than Day-Ahead to prevent over subscription. Hourly values for each Reciprocal entity will be calculated that will define their 6-NN Limit for those hours. Reciprocal entities will not grant any additional point-to-point firm service or Priorities 3 through 6 point-to-point non-firm services, beyond their respective allocations.

Reciprocal Market Entities may increase economic dispatch service respecting RCFs limits. Any additional impact on a RCF beyond defined priority 6 or 7 impacts after the 6-NN service is allocated will be represented as non-firm hourly, Priority 2 in the IDC. Reciprocal non-market entities may grant additional non-firm service. However, all non-firm service beyond priority 6 or 7 allocation will prioritized as Priority 2- NH, non-firm hourly service.

Current Day up to current hour:

Reciprocal entities may grant additional non-firm hourly service respecting RCFs limits. All non-firm service sold from designated time deadline Day Ahead will be considered as non-firm Priority 2 in the IDC.

Reciprocal Market Entities may increase economic dispatch service respecting RCFs limits. Any additional impact on a RCF beyond defined priority 6 or 7 impacts, from this point on will be represented as non-firm hourly, Priority 2-NH in the IDC

Real-time Operations Process

Operating Entity Capabilities

Capabilities remain as described in Section 5.

Operating Entity Real-time Actions

Procedures remain as described in Section 5. However, unlike the process utilized for Coordinated Flowgates, in which only market flows, NNL flows, and Economic Dispatch flows are provided, additional information regarding the firmness of those ED Flows will be communicated as well – a portion will be reported as NN-6, while the remainder will be reported as NH-2. This will provide additional ability for the IDC to curtail portions of the economic dispatch earlier in the TLR process.

Section 7 - Conclusion

PJM and MISO have worked extensively with one another and their respective stakeholders and the NERC Community to reliably address the congestion management/parallel flow seams issue identified in July of 2002.

The initiatives outlined in this paper address each of the four complexities of this critical seams issue. Highlighted in bold are these complexities – followed by a summary of how PJM and MISO have addressed each of these concerns.

In an LMP based market there are no internal transactions to tag. A security constrained economic dispatch is used to dispatch generation for the entire region. By calculating the economic flows caused by a large market's operations, the Operating Entity is ensuring that all flows are still being accounted for both within and external to the Operating Entity. Further, the Operating Entity calculations will allow the tracing and control of flows previously not addressed within the existing tag-based system. Additionally, by using re-dispatch in conjunction with transaction curtailments, the impacting Operating Entity will be able to provide more effective and timely relief to the constrained Reliability Coordinator.

The security constrained economic dispatch does not automatically honor external system constraints. Identifying and mitigating congestion impacts due to external system influences requires a different approach than contract path and use of TLR. This proposal sets a new standard for external coordination. Operating Entities with expanding markets will ensure that they track and respond to the market flows they create over an extensive list of Coordinated Flowgates. Additionally, this proposal offers an option for Inter-regional AFC coordination between Operating Entities. Through coordination of transmission service and by responding to real-time flows, Operating Entities will have a new and effective way to manage parallel flows.

An effective coordination agreement between MISO and PJM is necessary to minimize the probability of Level 5 TLRs. MISO and PJM's initiative will minimize the probability of TLR 5's because far more flows are being accounted for than they have been in the past. Additionally, with changes to flow determination and tagging the IDC will be armed with far more granularity than it has in the past. This granularity will provide Reliability Coordinators far more effective processes to control flows within a TLR 3.

PJM and MISO are confident that the initiatives outlined in this paper have addressed the MISO/PJM Congestion Management Reliability Seams Issue and will greatly enhance reliable operations throughout the Eastern Interconnection.

Section 8 - Appendices

Appendix A - Glossary

Control Zones - Within an Operating Entity control area that is operating with a common economic dispatch, the Operating Entity footprint is divided into control zones to provide specific zonal regulation and operating reserve requirements in order to facilitate reliability and overall load balancing. The zones must be bounded by adequate telemetry to balance generation and load within the zone utilizing automatic generation control.

Coordinated Flowgate – A flowgate impacted by a Market-Based Operating Entity by more than 5%, and subsequently subject to requirements under this proposal for data submission regarding MBOE impact on that flowgate.

Economic Dispatch Flow - Energy flow related to a Market-Based Operating Entity's market operations.

Generation Transfers - An Operating Entity that covers a large geographic area and operates a single control area with a market with common economic dispatch but separate regulation zones, will monitor transfers of energy between regulating zones as part of the overall load and generation balancing function of the control area. The calculated difference between the actual generation within a regulation zone and the load within that zone is the generation transfer.

Historic NNL - the NNL values that would have occurred if all control areas maintained their current configuration and continued to serve their native load with their generation

LMP Based System or Market - An LMP based system or market utilizes a physical, flow-based pricing system to price internal energy purchases and sales.

Locational Marginal Pricing (LMP) - Locational Marginal Pricing is the cost of supplying the next MW of load at a specific location, considering generation marginal cost, cost of transmission congestion, and losses. LMPs are equal when the transmission system is unconstrained. LMPs vary by location when the transmission system is constrained.

Market Flows - Market flows are the calculated energy flows on a specified flowgate or transmission facility as a result of economic dispatch of generating resources within a large Operating Entity Market.

Market-Based Operating Entity (MBOE) – An operating entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

Network Native Load (NNL) - Network native load is load, within the Operating Entity footprint, that the network customer designates for network integration transmission service and that is served by the output of any designated network resources.

NNL Flow - Energy flow related to contributions from the Network Native Load serving aspects of the dispatch.

NNL Limit -Defines the maximum value of Market Flows that can considered as due to NNL (and therefore firm)

Operating Entity – An entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

Reciprocal Coordinated Flowgate – A Coordinated Flowgate upon which coordination procedures and agreements have been written

Reciprocal Entity – An entity that has engaged in a reciprocal coordination agreement with another entity

Security Constrained Dispatch - Security Constrained Dispatch is the utilization of the least cost economic dispatch of generating and demand resources while recognizing and solving transmission constraints over a single Operating Entity Market.

Appendix B - NERC Policy Impacts

The MISO/PJM Policy Review Task Force is working with the MISO and PJM to identify what Policy changes may be necessary to enable the expansion of the LMP market over the PJM Operating Entity footprint. Appendix B will be modified as necessary to address other impacts that may be noted by the Task Force as their work progresses. The Policy Review Task Force is responsible for coordinating its work with the applicable NERC Subcommittees so that Policy changes can be developed and provided to the NERC Standing Committees for approval.

Appendix C - E-Tag and IDC Impacts

Overview

Much of the following was developed with the assistance of Open Access Technology, International (OATI) and the NERC IDC Working Group.

Proposed Changes

E-Tag Changes

To ensure that the IDC has enhanced granularity for transactions tagged in or out of a large market, MISO and PJM recommend that the IDC be reconfigured to accept the market's marginal units. By providing both the real-time and projected marginal units the IDC will be better able to model where generation is actually moving to support schedule changes. This recommended improvement differs significantly from the current IDC modeling of PJM transactions, because the calculations will not be using a static single point within the PJM system. The actual process for providing these units consists of the following:

a. MISO and PJM will determine these marginal units based upon the look-ahead solutions in their respective Unit Dispatch Systems the locations on the system where generation is expected to be marginal, and upload this information to the IDC.

b. MISO and PJM will indicate where the generation would move depending on the MW amount of curtailments that are necessary. There will be one or more sets of participation factors to represent exports from each market area and one or more sets of participation factors to represent imports into each market area..

c. This information would be transmitted in the form of adjustments to the generation participation factors that are already present in the IDC.

d. The IDC could then utilize this information in the calculation of control area to control area distribution factors instead of the current methodology of utilizing a static model of all generators within a control area's boundaries.

e. These locations could be as granular as individually identified generators. Note though, for market confidentiality reasons Operating Entity will mask the actual generator

f. PJM and MISO each simultaneously optimize and dispatch for all constraints currently confronting the system operators. Upon implementation of the inter-regional congestion coordination scheme, the Operating Entity would add to the current simultaneous constraint evaluation any flowgate for which the inter-regional congestion coordination had been initiated. Therefore, the marginal units the Operating Entity would transmit to the IDC for next hour curtailment evaluation would include the simultaneous evaluation of the flowgate for which curtailments would be requested. The IDC would in fact have all information necessary to accurately determine transaction distribution factors on the constrained facilities.

PJM and MISO propose that they will each supply to the IDC one or more sets of marginal source generators to be used to model all interchange transactions out of their respective markets for all flowgates. PJM and MISO propose that they will each supply the IDC one or more sets of marginal sink generators to be used to model all interchange transaction into their respective markets for all flowgates. These sets will be periodically updated by the Operating Entity through a new e-tag message. In addition, each Market Area will be partitioned into zones, and the Operating Entities will send the IDC marginal zone participation factors for more frequent updates. The Operating Entities will provide the IDC with different zonal participation factors for import and export. Depending on the market area configuration, topology, network impedance, geographical location, generation locations, one or more sets of marginal units may be appropriate to represent sinks in the IDC. The IDC should compute different TDFs for tags that source (export) and sink (import) into the market areas, based on the import and export participation factors.

- In order to overcome bandwidth restrictions, the IDC vendor (OATI) suggests PJM to partition its network into zones that can be modeled in the IDC. The number of zones should be small compared to the number of generators. PJM may have at least 12 to as many as 24 different zones. MISO will have at least 30 zones.

- Every hour, the Operating Entities would provide the IDC with the generator participation factors within each zone. The participation factors would be the same for all flowgates. IDC would calculate TDFs for every source/sink (and zone) for every flowgate.

- The IDC would publish TDFs for current and next hour for every zone.

- At every LMP cycle, the Operating Entities would provide the IDC with the zone weighting factors that are the same for all flowgates. Different zone weighting factors can be submitted for import (tags sinking in the market area) and export (tags sourcing in the market area).

- At the time of a TLR the IDC would dynamically compute a market area footprint TDF for import and export based on the most recently received zonal weighting factors, and use the footprint TDF for every tag that sources or sinks in the market area. This can be calculates by:

$TDF_{MA\text{-}Import} = \sum z\ W_{z\text{-}Import} \times TDF_z / \sum_z W_{z\text{-}Import}$
$TDF_{MA\text{-}Export} = \sum z\ W_{z\text{-}Export} \times TDF_z / \sum_z W_{z\text{-}Export}$

Where:

- $TDF_{MA\text{-}Import}$ is the Market Area footprint TDF for importing transactions
- $TDF_{MA\text{-}Export}$ is the Market Area footprint TDF for exporting transactions
- $W_{z\text{-}Import}$ is the Market Area zone z weighting factor for importing transactions
- $W_{z\text{-}Export}$ is the Market Area zone z weighting factor for exporting transactions
- TDF_z is the market Area zone z TDF

- The IDC currently archives the TDFs on a flowgate in TLR. The IDC would also archive the generator participation factors within the each market area zone and the zonal participation factors at the time the TLR is requested. This would provide the IDC users with the ability to audit the IDC results. The IDC could also update the market area footprint TDF every time the IDC receives new zonal weighting factors from the Operating Entity, which can be used by NERC for presentation through the NERC TDF viewer.

This approach provides the market with knowledge of TDFs, enables the IDC to publish much fewer values to the NERC sites – hourly (current and next hour) TDFs for the market area zones and other control areas and updates of the market area footprint TDF throughout the hour. It also reduces the traffic between the IDC and the Market Base Operating Entities, thus minimizing the communication infrastructure enhancement requirements.
Tagged transactions that source or sink in the market area would impact a flowgate based on the PJM footprint TDF on the flowgate, which is update throughout the hour based on zonal weighting factors. Transactions wheeled through the market area would only depend on the transactions source and sink TDFs.

IDC Changes

The requirement of this change order was developed to ensure the reliability of the bulk electric system is always maintained, and to ensure the NERC IDC is capable of determining accurate flow gate reductions representative of the entities actually creating the flows on the system. The expanded market footprints include additional control areas being incorporated into the existing PJM LMP market and MISO starting its LMP market, and involves the termination of using transmission reservations and NERC tags to represent system flows for those control areas internal to each market. The NERC IDC must be capable of receiving flow gate impacts created by each of the LMP markets.

Transactions going in and / or out, and through the PJM territory will continue to be tagged. Source / Sink bus points need to be determined in order to eliminate any type of gaming. During TLR, these tagged transactions will be curtailed as prescribed by the IDC, and could involve any of the current transmission priority buckets. The level of granularity and what E-tagging fields are used by the IDC to assign TDF factors to these transactions will be addressed in the near future.

In order to accomplish these changes necessary to incorporate the LMP markets into the IDC there will be NERC Policy, IDC software, algorithm, and database changes needed.

PROPOSED CHANGE DESCRIPTION:

IDC File Import Requirements:
The LMP market impact files will be sent to the IDC or specified location at least every fifteen minutes. These files will include market impact information for two transmission

priorities or categories, for every flow gate identified by the LMP Market agreement. This may not include all flowgates in the NERC BoF. IDC TDF calculations will continue to be done for the LMP market regions on all Flowgates to ensure that all tagged transactions from / into the market are curtailed properly during the TLR process.

The three transmission priorities that will be included in the LMP market impact file are:

1. Priority 2-NH (non-firm hourly Economic Impacts of LMP Market)
2. Priority 6-NN (Economic Impacts of LMP Market)
3. Priority 7-F (Firm NNL Impacts)

The LMP engine will transfer two types of files to the IDC or specified location. A Current hour file will be sent at least every fifteen minutes, and one next hour file will be sent at (and no later than) 25-minutes after the hour.
Each file will contain flow impact information for priority 2-NH, 6-NN, and 7-F for each identified flow gate. The LMP engine information associated with the flow gate calculations will be posted on the market OASIS for review.

The file transferred to the IDC will be in XML format. The field specifications will be identified when development begins.

If there is an error with the gathering/uploading or content of the LMP market impact file the values from the last good file will be used until a correct file can be retrieved. There should be an error sent to the RC to alert them of the file error.

LMP Flow Gate Impact Calculation Protocol:
Flow gate impact protocol "proposals" are identified in the PJM / MISO Congestion Management White paper. The flow gate protocol process will be added to this NERC IDC change order once a defined process has been approved.
IDC Weighting Factor Algorithm Change Requirements:
Since the LMP markets will be sending the flow impact for specified flowgates there will be no calculated TDF for that impact for use during the curtailment process. The weighting factor algorithm that is used to calculate the curtailments for priorities 2-NH, 6-NN and 7-FIRM will need to be changed.

The curtailment and reallocation of the priority 2-NH and 6-NN buckets will need to be modified to be like the curtailment in the priority 7-FIRM bucket to allow the flow impact information to be used to assign curtailment amounts on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions). Consequently all transactions using 2-NH and 6-NN Transmission Service will be put in the same sub-priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance. This change will also require a NERC Appendix 9C1 change in language.

The curtailment and reallocation of the priority 7-FIRM bucket will be the same with the exception that NO NNL Responsibility should be calculated for any of the CAs that are in the LMP market. The flow impact that will be sent to the IDC will already include the NNL portion for each area and there would be double counting if the 7-FIRM process also assigned NNL responsibility.

IDC Curtailment Report Change Requirements:
Non-firm schedule curtailments including transmission priority 1-NS through priority 5-NM will be prescribed for curtailment by the IDC as it is currently done.

Non-firm schedule curtailments of transmission priority 2-NH and 6-NN will include schedules identified by bucket 2-NH and 6-NN NERC tags, and by LMP market economic impacts. For non-firm priority 2-NH and 6-NN curtailments, the IDC curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR for each level as appropriate. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP economic impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 6-NN bucket where the status will return to "Proceed". The LMP market economic impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

Firm schedule curtailments of transmission priority #7 will include schedules identified by bucket #7 NERC tags, by control area NNL reductions, and by LMP market firm. The firm LMP market impact value used by the IDC will include firm schedules and NNL impacts created by the market as one number. For firm priority #7 curtailments, the IDC firm curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP FIRM impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 7-FIRM bucket where the status will return to "Proceed". The LMP market Firm impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

IDC Screen Change Requirements:
Various IDC screen options will be modified in order to display LMP market impacts. For example, when selecting the "whole transaction" list option for a particular flow gate, the IDC will display the LMP priority #6 and #7 accordingly. Some examples are included below.

NERC IDC Display Information:
The following pages represent NERC IDC screen displays. The displays provide information with respect to how the IDC works today, and how the tool will work with

the proposed LMP market change order. The Eau Claire – Arpin flow gate was used in the examples. The displays provide information for:

1) IDC "Whole Transaction list" for Eau Claire – Arpin as the tool is today.
2) IDC "Whole Transaction list" for Eau Claire – Arpin with the proposed LMP market change order.
3) TLR level 3B "Eau Claire – Arpin" Curtailment Report (50MWs of relief), as the tool works today, and with the proposed LMP market change order.
4) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155MWs of relief), as the tool works today.
5) TLR level 3B "Eau Claire – Arpin" Curtailment Report (155MWs of relief), with the proposed LMP market change order.
6) TLR level 3B "Eau Claire – Arpin" Curtailment Report (100MWs of relief), with the proposed LMP market change order

<u>Eau Claire – Arpin Flow Gate Information:</u>

The following IDC screen shot represents a NERC IDC "whole transaction" list as it works today.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	WL	MEC_TNSKDLJAN0278_EES	1 50	1-NS	1 50	1 50	1 50	11.0	11.0	7.1
MISO	WL	OTP_OTPW010007985_MPS	20	1-NS	20	20	20	2.4	2.4	12.2
PJM	CPM	NSP_NSPPOW0092573_PJM	280	1-NS	280	280	280	55.2	55.2	19.7
		Total for 1-NS	**450**		**450**	**450**	**450**	**68.6**	**68.6**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
MAIN	WL	MEC_AME010054962_PJM	150	2-NH	150	150	150	11.0	11.0	7.3
MISO	CPM	NSP_NSPPOW0092737_OPPD	6	2-NH	6	6	6	0.8	0.8	13.3
MISO	WL	WAUE_REMC010002263_MPS	250	2-NH	250	250	250	24.0	24.0	9.3
TVA	WL	MEC_APMM1JAN3024_AECI	50	2-NH	50	50	50	3.0	3.0	6.0
TVA	CPM	NSP_NSPPOW0092750_AECI	350	2-NH	350	350	350	69.0	69.0	19.7
		Total for 2-NH	**831**		**831**	**831**	**831**	**109.2**	**109.2**	
PJM	WL	KCPL_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	NPPD_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	ALTW_ALTMA10008672_ALTE	79	6-NN	79	79	79	12.2	12.2	15.4
MISO	CPM	CE_ALTMA10008643_ALTE	200	6-NN	200	200	200	12.8	12.8	6.4
MISO	CPM	CE_ALTMA10008651_ALTE	150	6-NN	150	150	150	9.6	9.6	6.4
MISO	CPM	OTP_WEPM24000813J_WEC	200	6-NN	200	200	200	51.2	51.2	25.6
MISO	CPM	WAUE_REMC010002261_WEC	300	6-NN	300	300	300	68.1	68.1	22.7
TVA	WL	MEC_APMM1JAN2912_AECI	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**737**		**737**	**737**	**737**	**86.4**	**86.4**	
MAIN	WL	MEC_CPS010101F00_AMRN	30	7-F	30	30	30	2.2	2.2	7.3
MAIN	WL	MEC_MECBULET01105_CE	360	7-F	360	360	360	38.2	38.2	10.6
MAIN	WL	MEC_MECBULET01106_AMRN	11	7-F	11	11	11	0.8	0.8	7.3
MISO	CPM	ALTE_WPPI010040617_WPS	10	7-F	10	10	10	1.0	1.0	9.6
MISO	CPM	ALTW_ALTMA10008479_ALTE	154	7-F	79	79	79	12.2	12.2	15.4
MISO	CPM	ALTW_ALTMA10008656_ALTE	50	7-F	50	50	50	7.7	7.7	15.4
MISO	WL	WAUE_UGPM010003879_MEC	300	7-F	300	300	300	17.1	17.1	5.7
MISO	WL	WAUE_UGPM010003880_MEC	200	7-F	200	200	200	11.4	11.4	5.7
MISO	CPM	WEC_CWPC010004010_WPS	4	7-F	4	4	4	0.4	0.4	9.6
MISO	CPM	WEC_WPSM010001684_UPPC	65	7-F	65	65	65	3.8	3.8	5.9
TVA	WL	LES_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	WL	MEC_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	WL	MEC_APMM1JAN2911_AECI	250	7-F	250	250	250	15.0	15.0	6.0
TVA	WL	MEC_MECBULET01003_AECI	150	7-F	150	150	150	9.0	9.0	6.0
		Total for 7-F	**1628**		**1628**	**1628**	**1628**	**63.5**	**63.5**	
		Global Total	**3759**		**3759**	**3759**	**3759**	**335.1**	**335.1**	

Eau Claire – Arpin Flow Gate Information:

The following IDC screen shot represents a NERC IDC "whole transaction" list with the proposed LMP market change order.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	CPM	NewCo_TNSKDLJAN0278_EES	50	1-NS	50	50	50	3.6	3.6	7.1
PJM	CPM	NewCo_NSPPOW0092573_PJM	168	1-NS	168	168	168	33.0	33.0	19.7
		Total for 1-NS	**238**		**238**	**238**	**238**	**36.9**	**36.9**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
PJM	CPM	NewCo_AME010054962_PJM	50	2-NH	50	50	50	3.6	3.6	7.3
EES	CPM	NewCo_APMM1JAN3024_EES	50	2-NH	50	50	50	3.0	3.0	6.0
FPL	CPM	NewCo_NSPPOW0092750_FPL	105	2-NH	105	105	105	20.6	20.6	19.7
		Total for 2-NH	**230**		**230**	**230**	**230**	**28.6**	**28.6**	
PJM	CPM	NewCo_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	SPC_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	NewCo LMP Market Economic Disp.		6-NN					79.3	
PJM	WL	PJM LMP Market Economic Disp.		6-NN					15.0	
EES	CPM	NewCo_APMM1JAN2912_EES	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**8**		**8**	**8**	**8**	**94.8**	**94.8**	
PJM	CPM	NewCo_CPS010101F00_PJM	30	7-F	30	30	30	2.2	2.2	7.3
PJM	CPM	NewCo_MECBULET01105_PJM	160	7-F	160	160	160	16.9	16.9	10.6
MISO	CPM	NewCo LMP Market NNL		7-F					120.0	
PJM	WL	PJM LMP Market NNL		7-F					16.0	
TVA	CPM	NewCo_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	CPM	NewCo_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	CPM	NewCo_APMM1JAN2911_AECI	142	7-F	142	142	142	8.5	8.5	6.0
TVA	CPM	NewCo_MECBULET01003_AECI	17	7-F	17	17	17	1.0	1.0	6.0
		Total for 7-F	**993**		**993**	**993**	**993**	**167.4**	**167.4**	
		Global Total	**2461**		**2461**	**2461**	**2461**	**335.1**	**335.1**	

Eau Claire – Arpin Flow Gate Information:

50MW of relief was required in this example. Only up to priority #3 was impacted.

	SC Requestor:	MISO	**CA Requestor:**	ALTE			**TLR level:**	3B	
	Requested Relief:	50							
	IDC MW Curtailed:	432	**Trans. Curt.**	8			**Relief:**	50	
Sink SC	**Tag Name**	**Method**	**Tag Marginal Priority**	**Schedule MW**	**Active MW**	**Curtail MW**	**MW Cap**	**Status**	**Relief Provided**
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.0
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
SWPP	OPPD_CRGL1ABJ0108J_EDE	WL	2-NH	50	50	50	0	CURTAIL	2.8
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTET0005785_PJM	WL	3-ND	53	53	16	37	CURTAIL	0.9
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	23	37	CURTAIL	1.7
									50.0
			Total Curtailment:	506	506	432	74		

****NOTE: The curtailment report above (when only including transmission curtailment priorities of bucket 0 – 5) will not change with the NERC IDC LMP market change order proposal.

Eau Claire – Arpin Flow Gate Information:

155MW of relief was required in the following example. Up to (and including) priority #6 was impacted.

The following IDC screen shot represents a NERC IDC "curtailment" list as it works today.

SC Requestor:	MISO	**CA Requestor:**	ALTE	**TLR level:**	3B
Requested Relief:	155				
IDC MW Curtailed:	1208	**Trans. Curt.**	24	**Relief:**	155

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTETD005785_PJM	WL	3-ND	53	53	53	0	CURTAIL	3.1
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	ALTW_ALTMA10008672_ALTE	CPM	6-NN	78	78	78	0	CURTAIL	12.0
MISO	CE_ALTMA10008643_ALTE	CPM	6-NN	100	100	67	33	CURTAIL	4.3
MISO	CE_ALTMA10008651_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008652_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008653_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008654_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_MSCG01MS39921_ALTE	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_MSCG01MS39922_WEC	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_WEPM24000813Q_WEC	CPM	6-NN	100	100	68	32	CURTAIL	4.4
MISO	MHEB_CRGL1AAA0107C_WEC	CPM	6-NN	100	100	100	0	CURTAIL	29.9
MISO	MPW_WEPM24000813X_WEC	CPM	6-NN	50	50	48	2	CURTAIL	5.5
MISO	MP_OTPW010007958_OTP	CPM	6-NN	50	50	29	21	CURTAIL	1.5
MISO	MP_OTPW010007975_OTP	CPM	6-NN	30	30	17	13	CURTAIL	0.9
MISO	NSP_WEPM24000813O_WEC	CPM	6-NN	100	100	50	0	CURTAIL	14.2
MISO	OTP_WEPM24000813J_WEC	CPM	6-NN	100	100	60	0	CURTAIL	12.7
MISO	WAUE_REMC010002261_WEC	CPM	6-NN	100	100	60	0	CURTAIL	13.2
TVA	MEC_APMM1JAN2912_AECI	WL	6-NN	8	8	5	3	CURTAIL	0.3
									156.
			Total Curtailment:	1522	1522	1208	184		

Eau Claire – Arpin Flow Gate Information:

155MW of relief was required in this example. Up to (and including) priority #6 was impacted.

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

	SC Requestor:	MISO	CA Requestor:	ALTE		TLR level:	3B		
	Requested Relief:	155							
	IDC MW Curtailed:	1338	Trans. Curt.	10		Relief:	155		

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	NewCo TNSKDLJAN0278 EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo NSPPOW0092573 PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI CRGL1ASH0107P EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo AME010054962 PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo APMM1JAN3024 EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo NSPPOW0092750 FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo CNCTET0005785 PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC TEA01TEO3010 AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		0	Re-Dispatch	80.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		0	Re-Dispatch	15.0
EES	NewCo APMM1JAN2912 EES	CPM	6-NN	50	50	50	0	CURTAIL	6.0
									156.0
			Total Curtailment:	611	706	1338			

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the control areas located outside the LMP market that have an NNL reduction responsibility.

Eau Claire – Arpin Flow Gate Information:

100MW of relief was required in this example. Up to priority #6 was impacted.

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

	SC Requestor:	MISO	CA Requestor:	ALTE		TLR level:	3B		
	Requested Relief:	100							
	IDC MW Curtailed:	1338	Trans. Curt.	10		Relief:	100		

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW / FG-Impact Cap	Status	Relief Provided
EES	NewCo TNSKDLJAN0278 EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo NSPPOW0092573 PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI CRGL1ASH0107P EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo AME010054962 PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo APMM1JAN3024 EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo NSPPOW0092750 FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo CNCTET0005785 PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC TEA01TEO3010 AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		45	Re-Dispatch	35.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		8	Re-Dispatch	7.0
EES	NewCo APMM1JAN2912 EES	CPM	6-NN	50	50	50	25	CURTAIL	3.0
									100.0
			Total Curtailment:	611	706	1338			

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the control areas located outside the LMP market that have an NNL reduction responsibility

Appendix D- Implementation Schedule

Feb-September 2003

- PJM & MISO continues to refine their respective models to include all Coordinated Flowgates
- PJM & MISO build processes to execute Whitepaper initiatives
- PJM & MISO implement Hold Harmless Rulings, as required

Sep-Nov 2003

- NERC Training Materials Distributed
- MISO and PJM conduct training, tests, and drills of the congestion management solutions
- MISO tests NNL calculations, PJM validates
- OATI Testing with MISO/PJM

Dec 2003

- MISO implements market throughout the MISO footprint
- MISO/PJM congestion management solutions are implemented.
- PJM/MISO improve processes when areas for improvement are identified (i.e., list of Coordinated Flowgates may grow)

2003 - 2004

- PJM implements market expansion through AEP/DPL, then ComEd, and then Dominion
- As PJM's market grows – additional versions of the Reliability Plan will require approval and list of Coordinated Flowgates will change with the addition of Dominion and ComEd
- MISO and PJM improve processes for Market to Market Operations
- Fall Seasonal NNL Calculations Updated
- Review Coordinated Flowgate List

Appendix E - PJM/MISO Examples and Case Studies

The following section provides several examples of how PJM and MISO will implement congestion management using the elements of the proposal. The first two illustrate the processes associated with a Coordinated Flowgate, while the third example shows the manner in which a Reciprocal Coordinated Flowgate would be managed. Following this are more detailed examples based on actual situations and data. For illustrative purposes, examples assume PJM has expanded its market and MISO is still a non-market based entity.

COORDINATED FLOWGATE GENERIC EXAMPLES

The following section outlines a number of examples of how PJM and MISO will implement congestion management using the elements of the proposal for Coordinated Flowgates.

EXAMPLE 1 - PJM Response on an overloaded PJM flowgate/facility –

PJM's Actions

1. PJM will initially determine whether there is excessive circulation through PJM's system. The definition of "excessive" circulation is dependent on system topology. As a general guide, circulation greater than 1000 MW across the Western Interface of PJM or circulation greater than 800 MW across the Northern interface of PJM can be considered excessive.
2. PJM will review the impact of circulation on constrained facility by:
    a. Performing a study TLR on the constrained flowgate to determine if external contracts > 5% impact are contributing to the PJM Constraint.
    b. Performing a study TLR on the interface flowgate associated with the constrained facility to determine if external contracts are the contributing factor to PJM Constraint.
    c. If external contracts with a 5% or greater impact are not the contributing factor skip steps 5 and 6.

    NOTE: In most cases PJM will be able to effectively avoid using the TLR steps, and handle congestion using its internal non-cost and re-dispatch procedures.
3. PJM will implement all non-cost measures (i.e., use of capacitors, line switching).
4. PJM will curtail all PJM contracts "Not willing to Pay Congestion".
5. PJM will issue a TLR if the study indicated external transaction (transaction not contracted through PJM that cause parallel flows) can be curtailed to relieve flowgate.
    a. Review Day-ahead packet to determine if any external contracts have confirmed "TLR_BUY_THRU" service.
    b. Contact the Sink Reliability Coordinator to notify him of "TLR buy-thru" service and that contract should not be curtailed per IDC prior to confirming TLR request.

c. Adjust energy schedules of PJM contracts "willing to pay thru" congestion, to ensure contracts are not curtailed as per IDC.
d. The Reliability Coordinator should direct the Transaction Dispatcher to note in their log, any NERC Tag ID's that were "protected" from curtailment by the TLR_BUY_THRU process, and the hours which they were protected.

6. PJM will re-issue TLR as required
7. After the excessive parallel flows are managed using the TLR, PJM will initiate off-cost re-dispatch as necessary to control for the overload.

NOTE: PJM's actions are not contingent on NNL or Economic Dispatch calculations/values. However, PJM will calculate these values for the PJM flowgates that will most likely require TLR operations. By doing these calculations, PJM can demonstrate to other Reliability Coordinators the PJM will have effectively re-dispatched when the TLR 3 reaches Bucket 6 curtailments.

MISO's ACTIONS – Example 1

1. MISO will only get involved with internal PJM congestion management when there is excessive circulation through the PJM system that requires PJM to initiate TLR operations.

NOTE: The amount of MISO's participation will not be driven by MISO's NNL or Economic Dispatch values (until MISO establishes its market); rather MISO's participation will be determined by the NERC IDC. In the initial implementation of this proposal only PJM will be calculating NNL and Economic Dispatch values.

2. If PJM has declared a TLR 3, MISO will respond in accordance with the procedures outlined in NERC Policy 9. As such, MISO will respond to the IDC Curtailment Lists – with the exception of any contracts that have on a day ahead basis asked PJM for a "TLR-Buy-thru" (in essence Market Re-dispatch). MISO Operators will know that PJM is re-dispatching for the impact of these particular contracts, because PJM Operators will have called the sink Reliability Coordinators.

EXAMPLE 2 – COORDINATED FLOWGATE

This is an example representing a Coordinated Flowgate external to PJM, the term Impacted Reliability Coordinator (RC) will refer to the party responsible for declaring a TLR on an overloaded facility.

1. Prior to an Impacted Reliability Coordinator having a problem on any of its Coordinated Flowgates, PJM is calculating Total Market Flows, NNL values, and the Economic Dispatch flows.
2. PJM will have uploaded both the real-time and hour ahead projected values of these three sets of flows. The projected values enable the Impacted Reliability Coordinator

of a Coordinated Flowgate to assess whether future schedule changes and change to PJM's dispatch may put a flowgate close of being in violation of its limit.

3. For this example the following table highlights the values PJM will be uploading to the IDC:

<table>
<tr><th colspan="4">FLOWGATE – Impacted RC - XYZ</th></tr>
<tr><th colspan="2">REAL-TIME
HOUR 13</th><th colspan="2">PROJECTED VALUES
HOUR 14</th></tr>
<tr><td rowspan="2">Total Market Flows
50</td><td>Economic Flows
50</td><td rowspan="2">Total Market Flows
70</td><td>Economic Flows
70</td></tr>
<tr><td>NNL Value
60</td><td>NNL Value
60</td></tr>
</table>

4. If system conditions are such that an Impacted RC sees no need to declare a TLR because total system flows on a flowgate do not have the flowgate at or near a limit violation, the Impacted RC and PJM continue to operate without change. Change (re-dispatch) is not required even though in the upcoming hour PJM's economic dispatch flows will exceed the PJM NNL value, because the overall system does not require relief.
5. As operations continue, a change in topology or schedules may indicate to the Impacted RC that their Flowgate XYZ will be in violation in the next hour. A part of the flows contributing to this overload could also be a change in PJM dispatch, in and above the NNL value for this flowgate.

<table>
<tr><th colspan="4">FLOWGATE – IMPACTED RC - XYZ</th></tr>
<tr><th colspan="2">REAL-TIME
HOUR 14</th><th colspan="2">PROJECTED VALUES
HOUR 15</th></tr>
<tr><td rowspan="2">Total Market Flows
70</td><td>Economic Flows
70</td><td rowspan="2">Total Market Flows
75</td><td>Economic Flows
75</td></tr>
<tr><td>NNL Value
60</td><td>NNL Value
60</td></tr>
</table>

IMPACTED RC ACTIONS – Example 2

1. IMPACTED RC monitors each of their flowgates and requests relief when required.
2. If IMPACTED RC sees that a flowgate will be in violation of its limit, IMPACTED RC will
    a. Perform a TLR study on the constrained flowgate to determine if external contracts > 5% impact are contributing to the IMPACTED RC Constraint.

   b. Perform a TLR study on the flowgate to determine which external contracts are the contributing factors to the IMPACTED RC Constraint.
   c. Review the IDC for whether PJM's economic flows are in excess of the NNL Value.
3. IMPACTED RC will initiate a TLR on the constrained flowgate.
   a. Depending upon the amount of relief requested by IMPACTED RC via the NERC IDC, IMPACTED RC's TLR will initially curtail transactions with transmission service in buckets 1 to 5.
   b. If additional relief is required, above the contract curtailments associated with buckets 1 through 5, IMPACTED RC will request additional relief in the TLR 3 that will curtail schedules with a bucket 6 transmission reservation.

PJM ACTIONS – Example 2, IMPACTED RC Flowgate

1. PJM will respond to the NERC IDC as it does today.
2. Upon the initiation of an IMPACTED RC TLR, PJM will acknowledge the TLR and the associated schedule curtailments. If bucket 6 schedules are being curtailed and the economic dispatch is in excess of the NNL, the IDC will indicate the amount of these excessive flows that will require redispatch. As per this example, PJM is 15 MW over the NNL value for Flowgate XYZ. Just as the IDC prorates curtailments over all of the impacting schedules within a bucket, the IDC will also pro-rate a proportion of these economic flows. For the purposes of this example, assume the IDC says that in addition to the schedules PJM may have to curtail it also has a redispatch commitment of 10 MW (10 of the 15 MW over the NNL value).
3. PJM's next step is to subtract these 10 MW to the total market flows, and treat the 65 MW as a limit to this flowgate.
4. PJM will use the 65 MW limit to bind its Unit Dispatch System – the simultaneously considers the most effective and reliable redispatch for all of the bound PJM constraints.
5. By binding Flowgate XYZ at a limit of 65 MW, PJM's UDS and Operators will ensure that the all of PJM's subsequent dispatch decisions honor this constraint, and keep the flows at 65 MW.
6. As the system changes, the IDC may indicate that both schedules can be reloaded and that the amount of redispatch commitment can be reduced. When the IDC does indicate a change to the re-dispatch commitment, PJM will adjust its binding limit to a higher value, once again continuing to respect this limit in all future dispatch decisions.
7. If IMPACTED RC requires further curtailments of bucket 6 – PJM may have to continue to lower this flowgate limit until the NNL value of 60 MW is reached.
8. If IMPACTED RC still requires additional relief – all of bucket 6 schedules may have to be fully curtailed; however, within TLR 3 once PJM has its economic dispatch equal to its NNL value PJM the IDC will not request PJM for a greater redispatch commitment and PJM will not typically redispatch further for the IMPACTED RC flowgate (coordinated emergency operations may be the exception to this point).
9. If all of bucket 6 has been curtailed and IMPACTED RC still requires additional relief on Flowgate XYZ, then IMPACTED RC will declare a TLR 5.

10. In a TLR 5, the IDC will calculate NNL contributions and assign NNL responsibilities to the impacting Reliability Coordinators. Assuming PJM receives a 5 MW responsibility for a TLR 5 event on Flowgate XYZ, than PJM would have to decrement the 5 MW off of the 60 MW NNL value.
11. PJM would then bind Flowgate XYZ in its UDS system with a limit of 55 MW. Once again, by binding the constraint at a particular limit all of PJM's subsequent dispatch decisions will ensure that the new lower limit is honored.

RECIPROCAL COORDINATED FLOWGATE EXAMPLE

EXAMPLE 3 – GENERIC MISO RECIPROCAL FLOWGATE

On a Day Ahead basis, PJM will bind its Reciprocal Flowgates to the limit of the allocated amount between parties (based on calculations described in Section 6). The Market RTO will utilize AFC-type calculations to considering these values in order to determine if there is any non-firm capacity available. (Non-Firm Priority 1 thru 5 schedules are not considered for this step). If there is additional capability PJM will schedule units up to the allocated amount, respecting both this limit and the inputs from the Reciprocal Entity. Non-firm committed in this day-ahead unit commitment, above the NNL value, will be treated in real-time as being Economic Dispatch (ED) - Bucket 6. During real-time operations anything above this day ahead economic dispatch value is considered non-firm hourly, Bucket 2. For the purposes of this example, day-ahead PJM calculated 15 MW of Economic Dispatch on Flowgate XYZ (these 15 MW will be treated as Bucket 6 by the IDC in real-time operations).

<table>
<tr><th colspan="4">RECIPROCAL FLOWGATE –MISO - XYZ</th></tr>
<tr><th colspan="2">REAL-TIME
HOUR 13</th><th colspan="2">PROJECTED VALUES
HOUR 14</th></tr>
<tr><td rowspan="3">Total Market Flows
50</td><td>Economic Flows
Bucket 6
0
Day-Ahead Value
15 MW</td><td rowspan="3">Total Market Flows
70</td><td>Economic Flows
Bucket 6
10
Day-Ahead Value
15 MW</td></tr>
<tr><td>Economic Flows
Bucket 2
0</td><td>Economic Flows
Bucket 2
0</td></tr>
<tr><td>NNL Value
60</td><td>NNL Value
60</td></tr>
</table>

1. Prior to MISO having a problem on any of its Coordinated Flowgates, PJM is calculating Total Market Flows, NNL values, and the Economic Dispatch flows (Bucket 6 and Bucket 2).
2. PJM will have uploaded both the real-time and hour ahead projected values of these four sets of flows (Change to Change Order 114). The projected values enable the MISO Reliability Coordinator to assess whether future schedule changes and changes to PJM's dispatch may put a flowgate close of being in violation of its limit.
3. For this example the following table highlights the values PJM will be uploading to the IDC:

<table>
<tr><th colspan="4">RECIPROCAL FLOWGATE – MISO - XYZ</th></tr>
<tr><th colspan="2">REAL-TIME
HOUR 13</th><th colspan="2">PROJECTED VALUES
HOUR 14</th></tr>
<tr><td rowspan="3">Total Market Flows

50</td><td>Economic Flows
Bucket 6

0
Day-Ahead Value
15 MW</td><td rowspan="3">Total Market Flows

80</td><td>Economic Flows
Bucket 6

15
Day-Ahead Value
15 MW</td></tr>
<tr><td>Economic Flows
Bucket 2

0</td><td>Economic Flows
Bucket 2

5</td></tr>
<tr><td>NNL Value

60</td><td>NNL Value

60</td></tr>
</table>

4. If system conditions are such that MISO sees no need to declare a TLR because total system flows on a flowgate do not have the flowgate at or near a limit violation, MISO and PJM continue to operate without change. Change (re-dispatch) is not required even though in the upcoming hour PJM's economic dispatch flows will exceed the PJM NNL value, because the overall system does not require relief.

5. As operations continue, a change in topology or schedules may indicate to MISO that their Flowgate XYZ will be in violation in the next hour. A part of the flows contributing to this overload could also be a change in PJM dispatch, in and above the NNL value for this flowgate.

<table>
<tr><th colspan="2">RECIPROCAL FLOWGATE – MISO - XYZ</th></tr>
<tr><th>REAL-TIME
HOUR 13</th><th>PROJECTED VALUES
HOUR 14</th></tr>
</table>

<table>
<tr><td rowspan="3">Total Market Flows

50</td><td>Economic Flows
Bucket 6

0
Day-Ahead Value
15 MW</td><td rowspan="3">Total Market Flows

80</td><td>Economic Flows
Bucket 6

15
Day-Ahead Value
15 MW</td></tr>
<tr><td>Economic Flows
Bucket 2

0</td><td>Economic Flows
Bucket 2

5</td></tr>
<tr><td>NNL Value

60</td><td>NNL Value

60</td></tr>
</table>

MISO ACTIONS – Example 3

1. MISO monitors each of their flowgates and requests relief when required.
2. If MISO sees that a flowgate will be in violation of its limit, MISO will
   a. Perform a TLR study on the constrained flowgate to determine if external contracts > 5% impact are contributing to the MISO Constraint.
   b. Perform a TLR study on the flowgate to determine which external contracts are the contributing factors to the MISO Constraint.
   c. Review the IDC for whether PJM's economic flows are in excess of the NNL Value + Day Ahead Bucket 6 Value.
3. MISO will initiate a TLR 3 on the constrained flowgate.
   a. Depending upon the amount of relief requested by MISO via the NERC IDC, MISO's TLR will initially curtail transactions with transmission service in buckets 1 to 5.
   b. In this example if the MISO TLR 3 only curtailed buckets 1 through 2, PJM would need to curtail the 5 MW of Economic Dispatch – that is flowing in and above the ED committed day-ahead, for this reciprocal flowgate (represented by the 15 MW in Bucket 6).
   c. If additional relief is required, above the contract curtailments associated with buckets 1 through 5, MISO will request additional relief in the TLR 3 that will curtail schedules with a bucket 6 transmission reservation. As such the 15 MW of ED within bucket 6 are available for additional curtailment.

PJM ACTIONS – Example 3, MISO Flowgate

1. PJM will respond to the NERC IDC, as it does today.
2. Upon the initiation of a MISO TLR, PJM will acknowledge the TLR and the associated schedule curtailments. If bucket 6 schedules are being curtailed and the economic dispatch is in excess of the NNL, the IDC will indicate the amount of these

excessive flows that will require redispatch. As per this example, PJM is 15 MW over the NNL value for Flowgate XYZ. Just as the IDC prorates curtailments over all of the impacting schedules within a bucket, the IDC will also pro-rate a proportion of these economic flows. For the purposes of this example, assume the IDC says that in addition to the schedules PJM may have to curtail it also has a redispatch commitment of 10 MW (10 MW of the 15 MW over the NNL value).

3. PJM's next step is to subtract these 10 MW to the total market flows, and treat the 65 MW as a limit to this flowgate.
4. PJM will use the 65 MW limit to bind its Unit Dispatch System – the simultaneously considers the most effective and reliable redispatch for all of the bound PJM constraints.
5. By binding Flowgate XYZ at a limit of 65 MW, PJM's UDS and Operators will ensure that the all of PJM's subsequent dispatch decisions honor this constraint, and keep the flows at 65 MW.
6. As the system changes, the IDC may indicate that both schedules can be reloaded and that the amount of redispatch commitment can be reduced. When the IDC does indicate a change to the re-dispatch commitment, PJM will adjust its binding limit to a higher value, once again continuing to respect this limit in all future dispatch decisions. The IDC's calculations to determine reallocations within the priority 6 bucket, will use the economic dispatch value at the start of the TLR as the reliability cap (in this example the cap would be 75 MW).
7. If MISO requires further curtailments of bucket 6 – PJM may have to continue to lower this flowgate limit until the NNL value of 60 MW is reached.
8. If MISO still requires additional relief – all of bucket 6 schedules may have to be fully curtailed; however, within TLR 3 once PJM has its economic dispatch equal to its NNL value PJM the IDC will not request PJM for a greater redispatch commitment and PJM will not typically redispatch further for the MISO flowgate (coordinated emergency operations may be the exception to this point).
9. If all of bucket 6 has been curtailed and MISO still requires additional relief on Flowgate XYZ, then MISO will declare a TLR 5.
10. In a TLR 5, the IDC will calculate NNL contributions and assign NNL responsibilities to the impacting Reliability Coordinators. Assuming PJM receives a 5 MW responsibility for a TLR 5 event on Flowgate XYZ, than PJM would have to decrement the 5 MW off of the 60 MW NNL value.
11. PJM would then bind Flowgate XYZ in its UDS system with a limit of 55 MW. Once again, by binding the constraint at a particular limit all of PJM's subsequent dispatch decisions will ensure that the new lower limit is honored.

SPECIFIC EXAMPLES

<u>Expanding Market Footprint – IDC Example 1</u>

Flowgate #7009 IMO-Frontier

Scenario: AEP and PJM areas combine into one market

Based on a snapshot of system conditions – March 14, 2003 at 1500 hrs.

Non-Firm AEP to PJM transactions: 1479 MW *(per IDC at 1500 hrs, 3/14/03)*
Firm AEP to PJM transactions: 23 MW *(per IDC at 1500 hrs, 3/14/03)*

I. Present IDC Methodology

Total relief available through transaction curtailment:
Non-Firm AEP to PJM transactions: 91 MW of relief
Firm AEP to PJM transactions: 1 MW of relief
(relief based on 6.16% TDF from IDC)

Determined NNL (>5% GLDF):
PJM: 1.0 MW
AEP: 0.0 MW

(All of the above numbers and factors are from the IDC at 1500 hrs on 3/14/03)

Total Available AEP/PJM relief under:
TLR 3: 91 MW
TLR 5: 2 MW (1 MW NNL + 1 MW Firm transactions)
Total: **93 MW**

II. MISO-PJM Proposal

A. Imposed "**Market Flow**" on IMO-Frontier: 104 MW
(based on GSFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

This calculation is determined based on the 'wide area' dispatch.

Assumption: All AEP and PJM generators are designated resources serving designated (combined footprint) load.

Where,
Market Flow =

∑ *(Individual Gen MW at 1500 hrs @ 3/14/03; both AEP and PJM units)*
* *(Generator to Load Distribution Factor of AEP/PJM combined footprint)*

GLDF of AEP/PJM combined footprint is the:
(Generator Shift factor (GSF) for each AEP/PJM unit)
\- *(Load Shift factor (LSF) of the AEP/PJM combined footprint)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.

The AEP/PJM load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling AEP/PJM load up 100 MW and supplying this load from the swing machine (same swing as in the IDC); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the AEP/PJM expanded market footprint LSF to be -4.5%.

Based on actual generation and load at 1500 hrs on 3/14/03, the combined AEP/PJM market was a net exporter of 284 MW. The marginal unit for PJM/AEP generation was reduced by this amount in the Market Flow calculation to 'back out' these exports (the marginal unit was assumed to reside in the BGE area).

B. Determined NNL (Historic Control Area footprint with counter flow):

PJM: 18 MW
AEP: -48 MW

(based on GLDFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

These calculations are determined based on the "local area" dispatch of both PJM and AEP individually.

Assumptions:

1. *Generation output levels are the same as those at 1500 hrs on 3/14/03. Generation levels used in NNL calculation are identical to generation levels used in market flow calculation.*

2. *All PJM generators are designated resources serving PJM load.*

3. *All AEP generators are designated resources serving AEP load.*

Where,
<u>PJM Historic NNL</u> =

$\sum$ *(Individual PJM Gen MW at 1500 hrs @ 3/14/03)*
* *(Generator to Load Distribution Factor of PJM)*

GLDF of PJM is the:
(Generator Shift factor (GSF) for each PJM unit)
\- *(Load Shift factor (LSF) of PJM)*

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.

The PJM load shift factor was provided by the IDC; this value was -6.5%.

Based on actual generation and load at 1500 hrs on 3/14/03, PJM was a net importer. 'Backing out' exports was not required.

<u>AEP Historic NNL</u> =

$\sum$ *(Individual AEP MW at 1500 hrs @ 3/14/03)*
* *(Generator to Load Distribution Factor of AEP)*

GLDF of AEP is the:
(Generator Shift factor (GSF) for each AEP unit)
\- *(Load Shift factor (LSF) of AEP)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

The AEP load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling AEP load up 100 MW and supplying this load from the swing machine (same swing as in the IDC base cases); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the AEP LSF to be 0.4%.

Based on actual generation and load at 1500 hrs on 3/14/03, AEP was a net exporter. To 'back out' this export from the AEP Historic NNL calculation, AEP generation was reduced (scaled down as the explicit AEP marginal unit was not known) by the export amount.

Assuming Historic Firm Transaction level is the same as the Firm AEP to PJM total of March 16 at 1500 hrs (e.g. 23 MW of transfer having 1 MW of impact on flowgate):

Total Historic NNL for AEP/PJM footprint:
18 MW + (-48) MW + 1 MW = -29 MW

Total Available AEP/PJM relief under:
TLR 3: 133 MW ((Economic Dispatch) = (Market Flow) – (Historic NNL))
TLR 5: 0 MW
Total: **133 MW**

In this example, MISO-PJM proposal provides an additional 42 MW of non-firm relief before a TLR 5 would be required.

Expanding Market Footprint – IDC Example 2

Flowgate #1634 Volunteer-Bull Run l/o WBN-Volunteer

Scenario: AEP and PJM areas combine into one market

Based on a snapshot of system conditions – March 14, 2003 at 1500 hrs.

Non-Firm AEP to PJM transactions: 1479 MW *(per IDC at 1500 hrs, 3/14/03)*
Firm AEP to PJM transactions: 23 MW *(per IDC at 1500 hrs, 3/14/03)*

I. Present Methodology

Total relief available through transaction curtailment:
Non-Firm AEP to PJM transactions: None
Firm AEP to PJM transactions: None
(AEP to PJM TDF is below IDC 5% threshold)

Determined NNL (>5% GLDF):
PJM: 0 MW
AEP: 46 MW

(All of the above numbers and factors are from the IDC at 1500 hrs on 3/14/03)

Total Available AEP/PJM relief under:

TLR 3: None
TLR 5: 46 MW
Total: **46 MW**

II. MISO-PJM Proposal

A. Imposed "**Market Flow**" on Volunteer-Bull Run: -159 MW
(based on GSFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

This calculation is determined based on the 'wide area' dispatch.

Assumption: All AEP and PJM generators are designated resources serving designated (combined footprint) load.

Where,
Market Flow =

$\sum$ *(Individual Gen MW at 1500 hrs @ 3/14/03; both AEP and PJM units)*
* *(Generator to Load Distribution Factor of AEP/PJM combined footprint)*

GLDF of AEP/PJM combined footprint is the:
(Generator Shift factor (GSF) for each AEP/PJM unit)
\- *(Load Shift factor (LSF) of the AEP/PJM combined footprint)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.

The AEP/PJM load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling AEP/PJM load up 100 MW and supplying this load from the swing machine (same swing as in the IDC); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were *normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the AEP/PJM expanded market footprint LSF to be 23%.*

Based on actual generation and load at 1500 hrs on 3/14/03, the combined AEP/PJM market was a net exporter of 284 MW. The marginal unit for PJM/AEP generation was reduced by this amount in the Market Flow calculation to 'back out' these exports (the marginal unit was assumed to reside in the BGE area).

B. Determined NNL (Historic Control Area footprint with counter flow):

PJM: -62 MW
AEP: -112 MW

(based on GLDFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

These calculations are determined based on the "local area" dispatch of both PJM and AEP individually.

Assumptions:

4. *Generation output levels are the same as those at 1500 hrs on 3/14/03. Generation levels used in NNL calculation are identical to generation levels used in market flow calculation.*
5. *All PJM generators are designated resources serving PJM load.*
6. *All AEP generators are designated resources serving AEP load.*

Where,
PJM Historic NNL =

∑ *(Individual PJM Gen MW at 1500 hrs @ 3/14/03)*
* *(Generator to Load Distribution Factor of PJM)*

GLDF of PJM is the:
(Generator Shift factor (GSF) for each PJM unit)
\- *(Load Shift factor (LSF) of PJM)*

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST *analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.*

The PJM load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling PJM load up 100 MW and supplying this load from the swing machine (same swing as in the IDC base cases); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the PJM LSF to be 22.8%.

Based on actual generation and load at 1500 hrs on 3/14/03, PJM was a net importer. 'Backing out' exports was not required.

<u>AEP Historic NNL</u> =

$\sum$ *(Individual AEP MW at 1500 hrs @ 3/14/03)*
* *(Generator to Load Distribution Factor of AEP)*

GLDF of AEP is the:
(Generator Shift factor (GSF) for each AEP unit)
\- *(Load Shift factor (LSF) of AEP)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

The AEP load shift factor was provided by the IDC; this value was 23.6%.

Based on actual generation and load at 1500 hrs on 3/14/03, AEP was a net exporter. To 'back out' this export from the AEP Historic NNL calculation, AEP generation was reduced (scaled down as the explicit AEP marginal unit was not known) by the export amount.

Assuming Historic Firm Transaction level is the same as the Firm AEP to PJM total of March 16 at 1500 hrs (e.g. 23 MW of transfer having 0 MW of impact on flowgate):

Total Historic NNL for AEP/PJM footprint:
-62 MW + (-112) MW = -174 MW

Total Available AEP/PJM relief under:
TLR 3: 15 MW ((Economic Dispatch) = (Market Flow) – (Historic NNL))
TLR 5: 0 MW
Total: **15 MW**

In this example, MISO-PJM proposal provides an additional 15 MW of non-firm relief before TLR 5 would be required.

Expanding Market Footprint – IDC Example 3

Flowgate #2315 Davis Besse-Lemoyne 345 flo Davis Besse-Bay Shore 345

Scenario: AEP and PJM areas combine into one market

Based on a snapshot of system conditions – March 14, 2003 at 1500 hrs.

Non-Firm AEP to PJM transactions: 1479 MW *(per IDC at 1500 hrs, 3/14/03)*
Firm AEP to PJM transactions: 23 MW *(per IDC at 1500 hrs, 3/14/03)*

I. Present Methodology

Total relief available through transaction curtailment:
Non-Firm AEP to PJM transactions: 0 MW of relief
Firm AEP to PJM transactions: 0 MW of relief
(relief based on -2.7% TDF from IDC)

Determined NNL (>5% GLDF):
PJM: 0.0 MW
AEP: 65.7 MW

(All of the above numbers and factors are from the IDC at 1500 hrs on 3/14/03)

Total Available AEP/PJM relief under:
TLR 3: 0 MW
TLR 5: 65.7 MW (1 MW NNL + 0 MW Firm transactions)
Total: 66 **MW**

II. MISO-PJM Proposal

A. Imposed "**Market Flow**" on flowgate 2315: 166 MW
(based on GSFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

This calculation is determined based on the 'wide area' dispatch.

Assumption: All AEP and PJM generators are designated resources serving designated (combined footprint) load.

Where,
<u>*Market Flow*</u> *=*

$\sum$ *(Individual Gen MW at 1500 hrs @ 3/14/03; both AEP and PJM units)*
* *(Generator to Load Distribution Factor of AEP/PJM combined footprint)*

GLDF of AEP/PJM combined footprint is the:
(Generator Shift factor (GSF) for each AEP/PJM unit)
\- *(Load Shift factor (LSF) of the AEP/PJM combined footprint)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.

The AEP/PJM load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling AEP/PJM load up 100 MW and supplying this load from the swing machine (same swing as in the IDC); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the AEP/PJM expanded market footprint LSF to be 2.3%.

Based on actual generation and load at 1500 hrs on 3/14/03, the combined AEP/PJM market was a net exporter of 284 MW. The marginal unit for PJM/AEP generation was reduced by this amount in the Market Flow calculation to 'back out' these exports (the marginal unit was assumed to reside in the BGE area).

B. Determined NNL (Historic Control Area footprint with counter flow):

PJM: 151 MW

AEP: 80 MW

(based on GLDFs from IDC, actual generator output; off-line analysis provided values not available from IDC)

These calculations are determined based on the "local area" dispatch of both PJM and AEP individually.

Assumptions:

7. *Generation output levels are the same as those at 1500 hrs on 3/14/03. Generation levels used in NNL calculation are identical to generation levels used in market flow calculation.*
8. *All PJM generators are designated resources serving PJM load.*
9. *All AEP generators are designated resources serving AEP load.*

Where,
<u>PJM Historic NNL</u> =

$$\sum \textit{(Individual PJM Gen MW at 1500 hrs @ 3/14/03)} * \textit{(Generator to Load Distribution Factor of PJM)}$$

GLDF of PJM is the:

(Generator Shift factor (GSF) for each PJM unit)

\- *(Load Shift factor (LSF) of PJM)*

If available, Generator Shift factors for PJM units were provided from the IDC as determined at 1500 hrs, 3/14/03. For GSFs not provided by the IDC (PJM has more units than the maximum number that the IDC will report GSFs for), off-line MUST analysis provided the GSFs. These off-line MUST GSFs were then normalized to values reported by the IDC at 3/14/03.

The PJM load shift factor was determined with off-line PSS/E analysis using IDC base cases. This was done by scaling PJM load up 100 MW and supplying this load from the swing machine (same swing as in the IDC base cases); the difference in flowgate flow before load scale and after load scale is the Load Shift Factor. The load shift factor was determined on the most recent winter and summer IDC base cases. The two values were normalized to TDF values from the IDC for the AEP and PJM LSFs and then averaged together to determine the LSF value used for the Market Flow determination. Analysis determined the PJM LSF to be 3.3%.

Based on actual generation and load at 1500 hrs on 3/14/03, PJM was a net importer. 'Backing out' exports was not required.

<u>AEP Historic NNL</u> =

$\sum$ *(Individual AEP MW at 1500 hrs @ 3/14/03)*
* *(Generator to Load Distribution Factor of AEP)*

GLDF of AEP is the:
(Generator Shift factor (GSF) for each AEP unit)
\- *(Load Shift factor (LSF) of AEP)*

All Generator Shift factors for the AEP units were provided from the IDC as determined at 1500 hrs, 3/14/03.

The AEP load shift factor was provided by the IDC; this value was -0.1%.

Based on actual generation and load at 1500 hrs on 3/14/03, AEP was a net exporter. To 'back out' this export from the AEP Historic NNL calculation, AEP generation was reduced (scaled down as the explicit AEP marginal unit was not known) by the export amount.

Assuming Historic Firm Transaction level is the same as the Firm AEP to PJM total of March 16 at 1500 hrs (e.g. 23 MW of transfer having -1 MW of impact on flowgate):

Total Historic NNL for AEP/PJM footprint:
151 MW + 80 MW + (-1 MW) = 230 MW

Total Available AEP/PJM relief under:
TLR 3: 0 MW ((Economic Dispatch) = (Market Flow) – (Historic NNL))
TLR 5: 230 MW
Total: **230 MW**

In this example, MISO-PJM proposal provides the same amount of non-firm relief as the present methodology. An additional 164 MW of relief is provided under a TLR 5 event.

Appendix F- List of Coordinated Flowgates

The following list contains 3rd-party flowgates (flowgates that will not reside in the expanded PJM RTO footprint) that are impacted by the Control Areas as indicated by the studies outlined in the Whitepaper: PJM, AEP, DPL, VAP, and CE**.**

Study Parameters:

PSS/E case used - The January 2003 IDC winter base case.

BOF - The BOF uploaded in the Feb update has been incorporated in the studies.

The (+/-) 5% or greater threshold was used in determining all the flowgates in this list.

The following Control Areas were used in the GLDF studies: (PJM, AEP, DPL), (VAP), and (CE).

The following Control Areas were used in the GLDF (n-2) studies: (PJM, AEP, DPL), (VAP), and (CE).

The following combinations were used in the CA-CA analysis, using the NERC TDF viewer and offline studies:

PJM, AEP, DPL						VAP		CE	
AEP to	PJM	DPL to	FE	PJM to	VAP	VAP to	PJM	CE to	AEP
AEP to	CPLE	DPL to	AEP	PJM to	FE	VAP to	CPLE	CE to	NIPS
AEP to	CPLW	DPL to	CIN	PJM to	AEP	VAP to	AEP	CE to	ALTW
AEP to	DUK			PJM to	DLCO			CE to	DELI
AEP to	VAP			PJM to	NYIS			CE to	AELC
AEP to	TVA							CE to	AMRN
AEP to	FE							CE to	IP
AEP to	OVEC							CE to	CILC
AEP to	CIN							CE to	ALTE
AEP to	DPL							CE to	WEC
AEP to	LGEE							CE to	MEC
AEP to	DLCO								
AEP to	IPL								
AEP to	NIPS								
AEP to	MECS								
AEP to	EKPC								
AEP to	DEWO								
AEP to	AEBN								
AEP to	IPRV								
AEP to	AMRN								
AEP to	IP								
AEP to	CE								

PJM, AEP, and DPL IMPACTED LIST OF FLOWGATES

The following list contains flowgates that are anticipated to be impacted by AEP and DPL joining the PJM RTO as well as the impact of the current PJM footprint. The list was obtained through studies outlined in the PJM-MISO Congestion Management Coordination White Paper. Note that flowgates that currently reside in PJM, AEP, and DPL will not be included in this list. Flowgates that are considered tie-lines into PJM, AEP or DPL will not be on this list. Tie-lines will already be included in the expanded PJM RTO model and monitored by PJM.

FLOWGATE ID	CONTROL AREAS	DESCRIPTION
3	PJM	PJM-EASTERN INTERFACE
4	PJM	PJM-CENTRAL INTERFACE
5	PJM	PJM- WESTERN INTERFACE
6	PJM,NYIS	Branchburg-Ramapo (5018) 500 kV line
20	PJM	Erie West-Erie South 345 kV line
21	PJM	Erie West 345/115 kV xfmr l/o Erie West-Erie South 345 kV
50	PJM	AP - SOUTH INTERFACE
1014	AECI,AMRN	Lutsvle-Essx-NMadrid for loss of Bland Franks
1016	AECI	Lutesville-Essex for the loss of Wilhelmina-NewMadrid & Wilhelmina-St. Francis
1017	EES,AECI,AMRN	NewMadrid-Dell for loss of Shelby-Lagoon Creek
1018	EES,AECI,AMRN	NewMadrid-Dell for loss of Ises-Dell
1019	EES,AECI,AMRN	NewMadrid-Dell for loss of Tiptonville
1106	CPLW	3ASHEVIL 115 6ASHEVL 230 98
1107	CPLW,DUK	3ASHEVIL-3MILLSRV
1201	SOCO,DUK,SC,SCEG	VACAR-SOUTHERN
1202	TVA,CPLW,DUK	VACAR-TVA
1204	DUK,CPLE	8NEWPORT 500 8RICHMON 500
1205	DUK,SOCO	8OCONEE 500 8NORCROS 500
1208	DUK	6ANTIOCH 230 6MITCH R 230
1209	DUK	6SHILOH 230 6PISGAH 230
1210	DUK	8OCONEE 500 6OCONEE 230
1222	DUK	Riverview-Ripp 230 kV line
1223	DUK	Riverview-Ripp 230 kV line
1351	EES,AECI	NewMadrid-Dell
1366	EES,AECI,AMRN	NewMadrid-Dell for loss of Marshall-Cumberland
1367	EES,AECI,AMRN	NewMadrid-Dell for loss of Shawnee-Marshall
1501	SOCO,TVA	Conasaga - Sequoyah 500
1510	SOCO,DUK	8NORCROS 500 80CONEE 500 1
1512	SOCO,SCEG	6VOGTLE 230 6S.R.P. 230 1
1608	TVA,EKPC	Wolf Creek - Russell 161
1613	TVA	Volunteer - Phipps Bend 500
1617	TVA,SOCO	SNP-Bowen&Oconee-Norcross
1619	TVA	JohnSevier-Vlntr#2&Vlntr-PhippsBnd500
1620	TVA	Cumbland-Davidson&Cumbland-Jvill
1621	TVA	Cumbland-Jvill&Cumbland-Davidson
1626	TVA,EKPC	Wolf Crk-Russell&Wolf Crk-WayneCo
1627	TVA,EKPC	Wolf Crk-Russell&PhippsBnd-Pocket
1628	TVA,EKPC	Wolf Crk-Russell&PhippsBnd-Vol
1631	TVA,LGEE	Pinevil-Pinevil&PhippsBnd-Pocket
1632	TVA,LGEE	Pinevil-Pinevil&Volunteer 500/161

1634	TVA	Volunteer-Bull Run&WBN-Volunteer
1638	TVA,EES	Shelby-Dell 500-kV
1641	TVA	Volunteer-PhippsBend 500 for Loss of Volunteer 500/161 xfmr
1702	VAP	8MORRSVL 500 8LOUDOUN 500
1704	CPLE,VAP	6PERSON 230 6HALIFAX 230
1707	CPLE,VAP	WAKE-CARSON 500
1708	VAP,CPLE	HALIFAX-PERSON 230/CARSON-WAKE 500
1709	VAP	CLOVER-HALIFAX 230/CLOVER-CARSON 500
1714	VAP,CPLE	EVERETS-PA-GRNV 230/CARSON-WAKE 500
1715	VAP	BALCFLS-SKIMMER 115/LEXNGTN-CLOVERD 500
1717	VAP	Fredricksburg-Possum Pt. 230 kV/Ladysmith-Possum Pt. 500 kV
1719	VAP	Mt. Storm-Doubs 500/Mt. Storm-Meadow Brook 500
1720	VAP	Loudoun 500-230 kV Tx #1/Loudoun 500-230 kV Tx #2
1721	VAP	Loudoun 500-230 kV Tx #2/Loudoun 500-230 kV Tx #1
2046	IPL,CIN	16PETE 345 08LOST R 345 1
2047	IPL,CIN	Petersburg-Gibson 345 flo Bedford-Gibson 345
2048	IPL,CIN	16SUNNYS 345 08GWYNN 345 1
2049	LGEE,CIN	12GHENT 345 08BATESV 345 1
2050	LGEE,CIN	12GHENT 345 08SPEED 345 1
2053	LGEE,CIN	Paddys West-Galagher 138 flo Jefferson-Rockport 765
2055	OVEC,CIN	06PIERCE 345 08FOSTER 345 1
2058	CIN,DPL	08ZIMER 345 09STUART 345 1
2059	CIN,EKPC	08BUFTN1 138 20BOONE 138 1
2062	CIN,IPL	08FVEP2 138 16FVE_T 138 1
2063	CIN,IPL	08WHITST 345 16GUION 345 1
2068	CIN,OVEC	08BKJ135 138 06PIERCE 345 1
2069	CIN,OVEC	08BUFTN1 345 06DEARB2 345 1
2070	CIN,OVEC	08BUFTN1 345 06PIERCE 345 1
2072	CIN	New London-Webster 230 flo Greentown-Jefferson 765
2089	OVEC,LGEE	06CLIFTY 345 11TRIMBL 345 1
2104	IPL	16PETE 345 16FRANCS 345 1
2129	NIPS,CE	17WOLFLK 138 SLINE; R 138 1
2130	EKPC,LGEE	20SPURLK 138 12KENTON 138 1
2184	FE,MECS	03BAY SH 345 19MON12 345 1
2185	FE,MECS	03LEMOYN-19MAJTC 345 flo 02BAY SH-19MON12 345
2186	FE,MECS	03ALLEN 345 19LULU 345 1
2187	LGEE	12W LEXI 345 12W LEXI 138 1
2189	LGEE	12BRWN N 345 12BRWN N 138 1
2190	LGEE	12BRWN N 345 12ALCALD 345 1
2191	LGEE	12ALCALD 345 12ALCALD 161 1
2192	LGEE	11PINEV 500 11PINEVI 345
2193	LGEE,TVA	12POCKET 500 8PHIPP B 500 1
2199	LGEE	Ghent-W.Lexington 345kV-Baker-Broadford
2201	LGEE	Brown South-Fawkes 138 kV
2203	CIN, OVEC	BUFFINGTON_345_138_PIERCE_FOSTER_345
2209	LGEE	W.Lex-E.W.Brown345 / Baker-Broadford765kv
2221	NIPS,CE	Munster-Burnham 345 flo Olive-E. Fra 345
2225	NIPS,CIN	Deedsville-Leesburg 345 flo Dumont 345/138 Tr
2233	NIPS	Michigan City-Trail Creek 138 flo Dumont-Stillwell 345
2236	FE,MECS	ALLEN-LULU 345 flo BAY SHORE-MONROE 345
2241	MECS,FE	MONROE-BAY SHORE 345 FLO LULU-ALLEN 345
2243	FE, MECS	BAY SHORE-MONROE 345 FLO MAJESTIC-ALLEN 345
2308	DLCO	15COLLIE 138 15ARSENL 138 1
2309	DLCO	15COLLIE 138 15ELWYN 138 1

2310	DLCO	15PHIL 138 15NORTH 138 1
2311	DLCO	15PHIL 138 15MTNEBO 138 1
2314	FE	03DAV-BE 345 03BAY SH 345 1
2315	FE	03DAV-BE 345 03LEMOYN 345 1
2316	FE	03ALLEN 345 03 ALLEN 138 1
2337	AEP,MECS	Cook-Palisades345/BentnHrbr-Palisades345
2340	MECS,AEP	TwinBranch-Argenta345/Cook-Palisades345
2357	PJM	Wylie Ridge #7 500/345 xfmr l/o Wylie Ridge #5 500/345 xfmr
2358	PJM	Wylie Ridge #5 500/345 xfmr l/o Wylie Ridge #7 500/345 xfmr
2401	CE,AEP	DUMONT765/345TX-DUMONT WILTON C 765
2403	AEP	KANAWZ-M FUNK 345/BAKER-BROADFORD 765
2406	AEP,VAP	CLVRDL-LXNGTN500/PRUNTYTN-MT STM500
2407	AEP,VAP	CLVRDL-LXNGTN500/MTSTM-VLY500&VLY500-230
2417	AEP,DUK	J Ferry-Antioch 500kV / Broadford-Sullivan 500 kV
2454	CIN	08S CRK 345 CAY CT 345 08WHEAT AMO 345
2457	CIN	Cayuga 345/230
2458	CIN	Cayuga 345/230 Cayuga Nucor 345
2459	CIN	08CAYUGA NUCOR 345 08CAYSUB 05EUGEN 345
2461	CIN	08GIBSON WHEAT 345 08GIBSON 16PETE 345
2462	CIN	08WHEAT QUALTC 345 08GIBSON 16PETE 345
2465	CIN	Speed-Ramsey 345 Buckner - Middletown 345
2466	CIN	Zimmer to Port Union 345 kV
2483	EKPC,LGEE	Avon - Loudon 138 kV
2484	LGEE,OVEC	Northside-Clify Creek 138 (flo) Trimble Co.-Clifty Creek 345
2485	LGEE,CIN	Gallagher-Paddys W 138 (flo) Trimble Co.-Clifty Creek 345
2486	LGEE,CIN	Speed-Northside 138 (flo) Trimble Co.-Clifty Creek 345
2855	MECS	BNSTNS-MON12/MON12-WAYNE
2856	MECS	MON12-WAYNE/BNSTNS-MON12
2859	MECS,FE	BAYSH-MON12/MON-MAJ-ALLEN
2861	MECS,FE	MON12-BAYSH/BAYSH-FOSTOR
3102	AMRN,AECI	BLAND-FRANKS 345 KV
3109	AMRN	RUSH ISLAND-ST FRANCOIS 345 KV
3111	IP,AMRN	XENIA -MT VERNON 345 KV
3112	AMRN,CILC	DUCK CREEK-IPAVA 345 kV
3113	AMRN	NEWTON-CASEY 345 KV
3115	AMRN	COFFEEN-PANA 345 KV
3117	AMRN,AECI	Bland-Franks345 + Rush-St Francios + TR
3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER
3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER
3133	AMRN	LABADIE-MASON3 + LABADIE-MASON4
3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID
3144	AMRN	RUSH-ST FRANCOIS + BLANDS-FRANKS
3155	AMRN	Lutsvle-Essx-NMadrid for loss of Bland Franks
3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345
3160	AECI,AMRN	Bland-Franks 345 for McCred-Overton 345
3216	CE	0621 Byron-ChV B for 0622 Byr-ChV R
3218	CE	0622 Byron-ChV R for 0621 Byr-ChV B
3222	CE	11601 EFrk-GoodiB for 11602 EF-GG R
3227	CE	0404 Quad-H471 for 15503 Cordo-Nelson
3229	CE	11604 Goodi-LockR for 11617GG-LockB
3230	CE	11617 Goodi-LockB for 11604GG-LockR
3234	CE	2102 Kincaid-Lath for 11215 Dum-Wlt
3245	CE	15616 Cher-Silv for 15502 Nels-EJ
3250	CE	15502 Nels-EJ for 15616 Cher-Silv

3252	CE	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81
3257	CE,MEC	Quad City-SUB 91 345 KV
3259	CE,MEC	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV
3260	CE	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345
3261	CE	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345
3304	CILC,CE	TAZEWELL-POWERTON 345 KV
3401	IP	SIDNEY XFMR + BUNSONVILLE XFMR
3402	AMRN,IP	CAHOKIA-BALDWIN+COFFEEN-ROXFRD TAP
3406	AMRN,IP	CAHOKIA-BALDWIN+ROXFD TP-STALLING
3410	IP	SIDNEY XFMR + DUMONT-WILTON
3412	IP	FAYET-TILDEN + BALDWN-MT VR345/138
3413	AMRN,IP	COFFN-ROXFD IP FOR XENIA-MT VRNON
3414	AMRN,IP	COFFN-ROXFD IP FOR COFFN N-COFFN
3416	IP	COFFEEN-ROXFORD 345
3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765
3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345
3420	IP	Coffeen-Roxford Jefferson-Rockport
3421	AMRN	Rush Isl-St Francios 345 for Franks-Salem 345
3422	AMRN	Rush Isl-St Francios345 for Mt Vern-Wfrank345
3423	AMRN	Bland-Franks 345 for Lutes-Essx345,Kelso Guid
3426	IP	Baldwin-Cahokia 345 for Baldw-Stallings,Stal TR
6081	MEC	Quad City West 345kV
6082	MEC	SUB 92-HILLS FOR LOSS OF LOUISA_SUB T
6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites - Sub 91
6117	MEC	Sub 92-Hills flo Sub 93-Sub T-Hills
7001	NYIS	FRONTIER - GENESSEE
7002	NYIS	GENESSEE - CENTRAL
7004	NYPA,NYIS	CENTRAL - CAPITAL
7006	NYIS	CAPITAL - WESTCHESTER
7007	NYIS	NYIS
7009	NYIS,IMO	IMO - FRONTIER
7101	IMO	BLIP-(Buchanan Longwood Input)
7102	IMO	QFW-(Queenston Flow West)
7104	IMO	NEGATIVE_BLIP(Negative Buch Lgwd Input)
7106	IMO,NYIS	FRONTIER - IMO
9009	FE,DLCO	FE-DLCO
9010	FE,MECS	FE-MECS
9032	OVEC,CIN	OVEC-CIN
9033	OVEC,LGEE	OVEC-LGEE
9042	CIN,LGEE	CIN-LGE
9043	CIN,IPL	CIN-IPL
9044	CIN,NIPS	CIN-NIPS
9045	CIN,EKPC	CIN-EKPC
9046	CIN,AMRN	CIN-AMRN
9059	LGEE,BREC	LGEE-BREC
9060	LGEE,EKPC	LGEE-EKPC
9061	LGEE,TVA	LGEE-TVA
9067	BREC,TVA	BREC-TVA
9080	NIPS,CE	NIPS-CE
9084	MECS,IMO	MECS-IMO
9088	EKPC,TVA	EKPC-TVA
9094	CPLE,DUK	CPLE-DUK
9095	CPLE,SCEG	CPLE-SCEG
9096	CPLE,SC	CPLE-SC
9097	CPLE,VAP	CPLE-VAP

9099	CPLW,DUK	CPLW-DUK
9100	CPLW,TVA	CPLW-TVA
9106	DUK,SOCO	DUK-SOCO
9111	SCEG,SOCO	SCEG-SOCO
9123	SOCO,TVA	SOCO-TVA
9138	TVA,IP	TVA-IP
9139	TVA,EES	TVA-EES
9156	NYIS,IMO	NYIS-IMO
9159	IMO,MECS	IMO-MECS
9160	IMO,NYIS	IMO-NYIS
9179	VAP,CPLE	VAP-CPLE

VAP IMPACTED LIST OF FLOWGATES

The following list contains flowgates that are anticipated to be impacted by VAP joining the PJM RTO as well as the impact of the current PJM footprint. The list was obtained through studies outlined in the PJM-MISO Congestion Management Coordination White Paper. Note that flowgates that currently reside in PJM, AEP, DPL, and VAP will not be included in this list. Flowgates that are considered tie-lines into PJM, AEP, DPL, or VAP will not be on this list. Tie-lines will already be included in the expanded PJM RTO model and monitored by PJM.

FLOWGATE ID	CONTROL AEAS	DESCRIPTION
1201	SOCO,DUK,SC,SCEG	VACAR-SOUTHERN
1204	DUK,CPLE	8NEWPORT 500 8RICHMON 500
7004	NYPA,NYIS	CENTRAL - CAPITAL
7101	IMO	BLIP-(Buchanan Longwood Input)
7104	IMO	NEGATIVE_BLIP(Negative Buch Lgwd Input)
9084	MECS,IMO	MECS-IMO
9094	CPLE,DUK	CPLE-DUK
9123	SOCO,TVA	SOCO-TVA
9156	NYIS,IMO	NYIS-IMO
9159	IMO,MECS	IMO-MECS
9160	IMO,NYIS	IMO-NYIS

CE IMPACTED LIST OF FLOWGATES

The following list contains flowgates that are anticipated to be impacted by CE joining the PJM RTO as well as the impact of the current PJM footprint. The list was obtained through studies outlined in the PJM-MISO Congestion Management Coordination White Paper. Note that flowgates that currently reside in PJM, AEP, DPL, VAP, and CE will not be included in this list. Flowgates that are considered tie-lines into PJM, AEP, DPL, VAP, or CE will not be on this list. Tie-lines will already be included in the expanded PJM RTO model and monitored by PJM.

FLOWGATE ID	CONTROL AREAS	DESCRIPTION
1011	AMRN,AECI	PalXfrPalSub
1201	SOCO,DUK,SC,SCEG	VACAR-SOUTHERN
1366	EES,AECI,AMRN	NewMadrid-Dell for loss of Marshall-Cumberland
1367	EES,AECI,AMRN	NewMadrid-Dell for loss of Shawnee-Marshall
1613	TVA	Volunteer - Phipps Bend 500
1634	TVA	Volunteer-Bull Run&WBN-Volunteer
1641	TVA	Volunteer-PhippsBend 500 for Loss of Volunteer 500/161 xfmr
3002	ALTE	NELSON-DEWEY 161/138 XFMR
3003	ALTE	COLUMBIA-S. FOND DU LAC 345 KV

3005	ALTE,WPS	S. FOND DU LAC-FITZGERALD 345 KV
3006	ALTE,NSP,WEC,WPS	EAU CLAIRE-ARPIN 345 KV
3009	NSP,ALTE,WEC,WPS	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK
3011	ALTE	PADDOCK 345/138 XFMR 1
3012	ALTE	PADDOCK XFMR 1 + PADDOCK-ROCKDALE
3014	ALTE	ROCKDALE XFMR 2 + PADDOCK XFMR
3015	ALTE	NELSON DEWEY XFMR+WMPLETOWN-PADDOCK
3016	ALTE	NELSON DEWEY XFMR + ECL-ARP+Guide
3017	ALTE,DPC	Cassvl-NED 161 for Wemp-Paddock 345
3018	ALTE,WPS,WEC,NSP	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON
3021	ALTE	PADDOCK-BLACKHAWK X53 PADDOCK-ROCK RIVER X39
3023	ALTE	ROE-Lkhd 138 for EauClair-Arp, Wien-Tcorners
3024	ALTE	Blackhwk-Cor X54 for Paddock-ROR X39 138
3025	ALTE	Russel-Rockdale 138/Paddock-Rockdale 345
3026	ALTE	Rockdale TR2 for Rockdale TR 1
3027	ALTE	N Lk Geneva Tp-Lk Geneva Wempltown-Paddock
3033	ALTE	Arpin Xformer+Arpin-Rocky Run 345
3034	ALTE	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345
3038	ALTE	Paddock-RockRiver 345-138 T3 FLO Paddock-Blkhwk138
3039	ALTE	Rockdale 345-138 T1 FLO Rockdale 345-138 T3
3040	ALTE	Rockdale 345-138 T2 FLO Rockdale 345-138 T3
3102	AMRN,AECI	BLAND-FRANKS 345 KV
3107	AMRN	MONTGOMERY-SPENCER 345 KV
3108	AMRN,MPS	OVERTON-SIBLEY 345 KV
3109	AMRN	RUSH ISLAND-ST FRANCOIS 345 KV
3111	IP,AMRN	XENIA -MT VERNON 345 KV
3112	AMRN,CILC	DUCK CREEK-IPAVA 345 kV
3113	AMRN	NEWTON-CASEY 345 KV
3115	AMRN	COFFEEN-PANA 345 KV
3117	AMRN,AECI	Bland-Franks345 + Rush-St Francios + TR
3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER
3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER
3127	AMRN	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID
3131	AMRN	PAWNE-AUBURN+KINCAID-LATHM
3133	AMRN	LABADIE-MASON3 + LABADIE-MASON4
3139	AMRN	PAWNEE WEST XFMR + PANA-KINCAID
3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID
3142	AMRN	RAMSEY-PANA + COFFEEN-PANA-KINCAID
3144	AMRN	RUSH-ST FRANCOIS + BLANDS-FRANKS
3145	AMRN	PANA XFMR + COFFEEN-COFFEEN NORTH
3157	AMRN	McCredie-Overton345 for Bland-Franks 345
3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345
3160	AECI,AMRN	Bland-Franks 345 for McCred-Overton 345
3301	CILC	TAZEWELL - MASON 138 KV
3302	CILC	HOLLAND - E SPRINGFIELD 138 KV
3303	CILC,CWLP	E SPRINGFIELD-EASTDALE 138 KV
3306	CILC	Holland-Mason138+Duck Creek-Tazewell345
3402	AMRN,IP	CAHOKIA-BALDWIN+COFFEEN-ROXFRD TAP
3406	AMRN,IP	CAHOKIA-BALDWIN+ROXFD TP-STALLING
3409	IP	PANA-MOWEAQ T + PONTIAC-LATHAM
3412	IP	FAYET-TILDEN + BALDWN-MT VR345/138
3413	AMRN,IP	COFFN-ROXFD IP FOR XENIA-MT VRNON
3414	AMRN,IP	COFFN-ROXFD IP FOR COFFN N-COFFN
3416	IP	COFFEEN-ROXFORD 345

3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765
3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345
3420	IP	Coffeen-Roxford Jefferson-Rockport
3421	AMRN	Rush Isl-St Francios 345 for Franks-Salem 345
3422	AMRN	Rush Isl-St Francios345 for Mt Vern-Wfrank345
3423	AMRN	Bland-Franks 345 for Lutes-Essx345,Kelso Guid
3426	IP	Baldwin-Cahokia 345 for Baldw-Stallings,Stal TR
3502	WEC	OAK CREEK 345/230 XFMR
3503	WEC	ALBERS-PARIS 138 KV
3507	ALTE,WEC	EDGEWATER-Cedarsauk-Granville 345 KV
3509	ALTE,WEC	MUR 138-MULLET RVR 138 KV
3515	WEC	JEFFERSON-LAKEHEAD 138 KV
3517	WEC	ARCADIAN-GRANVILE 345 KV
3518	WEC	BUTLER-GRANVILE+ARCADIAN-GRANVILE
3520	WEC	Merril-Hil 138 for Wemp-Paddock 345
3522	WEC	Albers-Paris138 for Wemp-Padock 345
3523	WEC	Stiles-Pioneer 138 for N.Appl-WhiteClay138
3527	WEC	PleasPr-Racine 345 for Wemp-Pad 345
3528	WEC	N Appleton-Wh Clay 138 for Stiles-Pulliam 138
3529	WEC	N. Appleton-Rocky Run 345kV
3530	WEC	Jeffrsn-LakehdCam138 Col-SFL345
3534	WEC	Kenosha-Albers 138 for Wempletown-Paddock 345
3537	WEC	Kenosha-Lakeview 138 for PleasPr-Zion 345
3538	WEC,WPS	STILES4-PULLIAM 138+STILES5-PULLIAM 138
3542	WEC	Amberg-Plains 138 flo Morgan-Plains 345
3544	WEC	Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345
3550	WEC	N.Appleton-WhiteClay138 FLO Stiles-Pulliam138
3556	WEC	Plains-Amberg138 FLO Morgan-Plains345
3557	WEC	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345
3558	WEC	PleasPrairie-Arcadian345 FLO Zion-Arcanian345
3560	WEC	Whitewater-Mukwonago FLO CherryVal-SilvrLk345
3565	WEC	Paris-Burlington 138 (flo) Wempletown-Paddock 345
3601	ALTE,WPS	ARPIN - ROCKY RUN 345 KV
3602	WPS,WEC	ROCKY RUN - N APPLETON 345 KV
3612	WEC,WPS	N APPLETON-FITZGERALD 345KV
3623	WPS, WEC	Kewaunee-N.Appleton xfmr FLO N.Appleton-PtBeach345
3624	WPS, WEC	Kewaunee-PtBeach345 FLO N.Appleton-PtBeach345
3704	ALTW	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345
3705	ALTW	Arnold-Hazelton 345 for Wemp-Paddock 345
3707	ALTW	LOR5-TRK RIV5 161KV/WEMPL-PADDOCK 345KV
3711	ALTW	Albany 161-138 for Nelson-Cordo B 345
3716	ALTW	Rock Creek 345/161 TR for Quad-Sub 91 345
3717	ALTW	Rock Creek-Dewitt 161 Quad Cities-Sub91 345
3718	ALTW	RockCreek-Dewitt 161 for meccord3-sub39 345kV
3719	ALTW	Salem 345/138 Quad Cities-Sub 39
3720	ALTW	Salem 345-138 TR for MEC Cordova-Sub 39 345kV
3721	ALTW	Salem 345/161 for Quad-Sub 91 TR
3723	ALTW	Tiffton-D.Arnold 345 for Montezuma-Hills 345kV
3725	ALTW	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345
3732	ALTW	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500
5050	MPS,KCPL	StjLakIatStr
6004	ALTE,WEC,WPS,NSP	MWSI
6009	NPPD,MPS,AECI,OPPD	COOPER_S
6014	OPPD	FTCAL_S

6015	DPC,NSP	ROCHSTR-ALMA / KING-ECL
6017	SMP,ALTW	LAKEFIELD XFMR / BYRON-ADAMS
6030	NPPD,OPPD	Nebraska City-Cooper 345kV
6057	MEC	Sub T-Hills 345kV FLO Sub 93-Sub 92 345kV
6062	SMP,NSP	Cascade Creek - Crosstown 161 (flo) King - Eau Claire
6069	DPC,NSP	Wabaco - Alma 161KV (flo) Eau Claire - Arpin 345KV
6073	MEC,WAUE	Morningside-Plymouth 161kV FLO Raun-Sioux City 345kV
6074	MEC	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV
6081	MEC	Quad City West 345kV
6082	MEC	SUB 92-HILLS FOR LOSS OF LOUISA_SUB T
6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites - Sub 91
6086	MEC	Montezuma-Bondurant 345kV
6088	DPC,NSP	Genoa-Seneca (flo) Eau Claire-Arpin
6104	MPS	Iatan - St. Joe 345kV
6108	ALTW, DPC	TURKEY RVR-CASSVILLE FLO WEMP-PADDOCK
9010	FE,MECS	FE-MECS
9139	TVA,EES	TVA-EES

MISO – LIST OF FLOWGATES

Study Parameters:

PSS/E case used - The April 2003 IDC winter base case.
BOF - The BOF uploaded in the April update has been incorporated in the studies.
The (+/-) 5% or greater threshold was used in determining all the flowgates in this list.
The following Control Areas were used in the GLDF studies:

The following combinations were used in the CA-CA analysis, using the NERC TDF viewer and offline studies:

NERC CA(s) Included in MISO Market Footprint

		**Notes
AEWC	Allegheny Energy Supply Company, LLC	Generation Only
AEWI	Allegheny Energy Supply Company, LLC	Generation Only
ALTE	Alliant Energy - CA	
ALTW	Alliant Energy - CA	
AMRN	Ameren Transmission	
CILC	Central Illinois Light Co	
CIN	Cinergy Corporation	
CWLD	Columbia Water and Light	
CWLP	City Water Light & Power	
DEVI	DECA, LLC	Generation Only
FE	First Energy	
HE	Hoosier Energy	
IPL	Indianapolis Power & Light Company	
LES	Lincoln Electric System	
LGEE	LG&E Energy Transmission Services	
MDU	Montana Dakota Utilities	Pseudo

MECS	Michigan Electric Coordinated System
MGE	Madison Gas and Electric Company
MHEB	Manitoba Hydro Electric Board
MP	Minnesota Power, Inc.
MPS	Aquila Networks - MPS
NIPS	Northern Indiana Public Service Company
NSP	Northern States Power Company
OTP	Otter Tail Power Company
SIGE	Southern Indiana Gas and Electric
SIPC	Aouthern Illinois Power Cooperative
UPPC	Upper Peninsula Power Co.
WEC	Wisconsin Energy Corporation
WPEK	Aquila Networks - WPK
WPS	Wisconsin Public Service Corporation

NERC FG #	FG Description	CA Owners	FG Type
3	PJM- WESTERN INTERFACE	PJM	Rel,Le
4	PJM-CENTRAL INTERFACE	PJM	Rel,Le
5	PJM- WESTERN INTERFACE	PJM	Rel,Le
12	Warren-Falconer 115 kV line	PJM,NYIS	Rel,Le
13	Erie East-South Ripley 230 kV line	PJM,NYIS	Rel,Le
14	East Towanda-Hillside 230 kV line	PJM,NYIS	Rel,Le
15	East Sayre-North Waverly 115 kV line	PJM,NYIS	Rel,Le
17	Homer City-Stolle Road 345 kV line	PJM,NYIS	Rel,Le
18	Homer City-Watercure Road 345 kV line	PJM,NYIS	Rel,Le
20	Erie West-Erie South 345 kV line	PJM	Rel,Le
21	Erie West 345/115 kV xfmr l/o Erie West-Erie South 345 kV	PJM	Rel(OTDF), LODF
22	Erie West-Erie South 345 kV l/o Homer City-Stolle Rd 345 kV	PJM	Rel(OTDF), LODF
50	AP - SOUTH INTERFACE	PJM	Rel,Le
100	Kammer #8 xfmr l/o Belmont-Harrison 500	PJM	Rel(OTDF), LODF
101	Kammer #8 xfmr l/o Kammer-South Canton 765 kV line	PJM,AEP	Rel(OTDF), LODF
110	Wylie Ridge #7 tx l/o Wylie #5 tx (WK3 CB open - OP Proc.)	PJM	Rel(OTDF), LODF
1001	FptLatIatStr	AECI,AMRN	Rel(OTDF)
1002	ThmMobThoMcc	AECI,AMRN	Rel(OTDF),LODF
1003	ThmMobThmSal	AECI,AMRN	Rel(OTDF),LODF
1004	MccTieAECAMRN	AECI,AMRN	Rel
1005	MarXfrBlaFra	AECI,AMRN	Rel(OTDF)
1010	MccTieAMRN AEC	AECI,AMRN	Rel
1011	PalXfrPalSub	AMRN,AECI	Rel(OTDF),LODF
1014	Lutsvle-Essx-NMadrid for loss of Bland Franks	AECI,AMRN	Rel(OTDF),LODF
1015	Fairport-Lathrop for the loss of StJoe-Hawthorne(LakeRd-Nashua)	AECI	Rel(OTDF),LODF
1016	Lutesville-Essex for the loss of Wilhelmina-NewMadrid & Wilhelmina-St. Francis	AECI	Rel(OTDF)
1017	NewMadrid-Dell for loss of Shelby-Lagoon Creek	EES,AECI,AMRN	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
1018	NewMadrid-Dell for loss of Ises-Dell	EES,AECI,AMRN	Rel(OTDF),LODF
1019	NewMadrid-Dell for loss of Tiptonville	EES,AECI,AMRN	Rel(OTDF),LODF
1020	New Madrid 345/500 #1 for Loss of MarshallCumberland500	AECI	Rel(OTDF), LODF
1021	New Madrid 345/500 #1 for Loss of Shelby-LagoonCrk500	AECI	Rel(OTDF), LODF
1203	8ANTIOCH 500 05J.FERR 500	DUK,AEP	Rel
1205	8OCONEE 500 8NORCROS 500	DUK,SOCO	Rel(OTDF),LODF
1318	RusselvilleS-DardanelleDam for loss of ANO-FtSmith	EES,OKGE	Rel(OTDF)
1320	ANO-FtSmith for loss of ANO500-161	EES,OKGE	Rel(OTDF)
1321	ANO-FtSmith for loss of Pleasant Hill-ANO	EES,OKGE	Rel(OTDF)
1324	WhiteBluff-Sheridan for loss of Mabelvale-Sheridan	EES	Rel(OTDF)
1326	Mabelvale-Sheridan for loss of WhiteBluff-Sheridan	EES	Rel(OTDF)
1330	McAdams500-230 for loss of McAdams-Lakeover	EES	Rel(OTDF)
1331	Lakeover115-500 for loss of RayBraswell-Lakeover	EES	Rel(OTDF)
1332	Ray Braswell 500/230 for the loss of Ray Brasswell - Lakeover	EES	Rel(OTDF)
1340	Sheridan-WhiteBluff for loss of Mabelvale-Wrightsville	EES	Rel(OTDF)
1341	Sheridan-ElDorado for loss of HotSprings-Etta	EES	Rel(OTDF)
1342	Sheridan-ElDorado for loss of Sheridan-HotSprings	EES	Rel(OTDF)
1346	DanielSOCO-McKnight	EES,SOCO	Rel,Cont.
1351	NewMadrid-Dell	EES,AECI	Rel,MRD
1352	ISES-Dell	EES	Rel,MRD
1354	RayBraswell-Lakeover	EES	Rel
1355	Gypsy-Fairview for the loss of McKnight-Franklin	EES	Rel(OTDF)
1358	McAdams-LakeOver	EES	Rel
1361	ElDorado-MtOlive	EES	Rel
1362	Nelson 500/230	EES	Rel
1363	OTDF WebRic for loss of MtOliveHartbrg	EES	Rel(OTDF)
1364	Frnkln-RayBras for loss of Frnkln-Bogalusa	EES	Rel(OTDF)
1365	West Memphis - Birmingham Steel for the loss of Dell - Shelby	EES	Rel(OTDF)
1366	NewMadrid-Dell for loss of Marshall-Cumberland	EES,AECI,AMRN	Rel(OTDF)
1367	NewMadrid-Dell for loss of Shawnee-Marshall	EES,AECI,AMRN	Rel(OTDF)
1368	Franklin-McKnight for loss of Webre-Richard	EES	Rel(OTDF)
1369	HotSprings-Etta for loss of Sheridan-ElDorado	EES	Rel(OTDF)
1377	Fairport-Lathrop for loss of Iatan-Stranger (LakeRoad-Nashua OpGuide)	AECI,AMRN	Rel(OTDF)
1383	Sheridan-Hotsprings for the loss of Sheridan-Eldorado	EES	Rel(OTDF),LODF
1388	Mt. Olive - Hartburg for the loss of Webre - Richard	EES	Rel(OTDF),LODF
1396	Michoud-FrontStreet for loss of McKnight-Franklin 500 kV	EES	Rel(OTDF),LODF
1397	Dell - Shelby for the loss of West Memphis - Birmingham Steel	EES	Rel(OTDF)
1501	Conasaga - Sequoyah 500	SOCO,TVA	Rel
1504	Miller500-Bellefonte#2&MillerLowndes	SOCO,TVA	Rel(OTDF),LODF
1505	Miller-Lowndes500&Daniel-McKnight	SOCO,TVA	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
1510	8NORCROS 500 80CONEE 500 1	SOCO,DUK	Rel
1512	6VOGTLE 230 6S.R.P. 230 1	SOCO,SCEG	Rel(OTDF)
1528	8DANIEL 550 MCKNT 8 500 1	SOCO,EES	Rel(OTDF)
1538	8MILLER 500 6MILLER 230	SOCO	Rel(OTDF)
1608	Wolf Creek - Russell 161	TVA,EKPC	Com
1609	Shawnee - C37A 161	TVA	Rel
1612	Shawnee 161/500 Transformer	TVA	Rel
1613	Volunteer - Phipps Bend 500	TVA	Rel
1615	Shawnee-Clinton161&Shawnee161/500trf	TVA	Rel(OTDF)
1620	Cumbland-Davidson&Cumbland-Jvill	TVA	Rel(OTDF)
1621	Cumbland-Jvill&Cumbland-Davidson	TVA	Rel(OTDF)
1622	Summer-Paddys&Sullivan-Broadford	TVA,LGEE	Rel(OTDF)
1624	Summer-SShadt&Summer-Sshade	TVA,EKPC	Rel(OTDF)
1625	Summer-SShade&Summer-Sshadt	TVA,EKPC	Rel(OTDF)
1626	Wolf Crk-Russell&Wolf Crk-WayneCo	TVA,EKPC	Rel(OTDF)
1627	Wolf Crk-Russell&PhippsBnd-Pocket	TVA,EKPC	Rel(OTDF)
1628	Wolf Crk-Russell&PhippsBnd-Vol	TVA,EKPC	Rel(OTDF)
1631	Pinevil-Pinevil&PhippsBnd-Pocket	TVA,LGEE	Rel(OTDF)
1634	Volunteer-Bull Run&WBN-Volunteer	TVA	Rel(OTDF)
1635	Marshall Bank	TVA	Rel
1638	Shelby-Dell 500-kV	TVA,EES	Rel
1639	Kentucky-Livingston 161-kV	TVA,LGEE	Rel
1640	Calvert-Livingston 161-kV	TVA,LGEE	Rel
1641	Volunteer-PhippsBend 500 for Loss of Volunteer 500/161 xfmr	TVA	Rel(OTDF), LODF
1701	01PRNTY 500 8MT STM 500	PJM,VAP	Rel
1706	CLOVERDALE-LEXINGTON 500	VAP,AEP	Rel
1708	HALIFAX-PERSON 230/CARSON-WAKE 500	VAP,CPLE	Rel(OTDF)
1712	DICKERSN-PL VIEW 230/DOUBS-LOUDOUN 500	PJM,VAP	Rel(OTDF)
1713	DICKERSN-PL VIEW 230/BURCHES-POSSUM 500	PJM,VAP	Rel(OTDF)
1719	Mt. Storm-Doubs 500/Mt. Storm-Meadow Brook 500	VAP,PJM	Rel(OTDF)
2004	05MARYSV 765 05MARYSV 345 1	AEP	Rel,Le
2005	05MARYSV 05E LIMA 345-MARYSV SWLIMA 345	AEP	Rel(OTDF),Le
2006	05SCANTO 765 05SCANTO 345 1	AEP	Rel,Le
2007	05COOK 765 05COOK 345 1	AEP	Rel,Le
2008	05DUMONT 765 05DUMTEQ 999 1	AEP	Rel,Le
2009	05COOK 345 05BENTON 345 1	AEP	Rel,Le
2010	05COOK 345 18PALISA 345 1	AEP,MECS	Rel,Le
2011	05ROB PK 345 18ARGENT 345 1	AEP,MECS	Rel,Le
2012	05TWIN B 345 18ARGENT 345 1	AEP,MECS	Rel,Le
2014	05OLIVE 345 UPNOR;RP 345 1	AEP,CE	Rel,Le
2015	05OLIVE 345 G ACR; T 345 1	AEP,CE	Rel,Le

NERC FG #	FG Description	CA Owners	FG Type
2016	05FALL C 345 05DESOTO 345 1	AEP	Rel,Le
2017	05COOK 345 05OLIVE 345	AEP	Rel,Le
2018	05DARWIN 345 05EUGENE 345 1	AEP	Rel,Le
2020	06KYGER 345 05SPORN 345 1	OVEC,AEP	Rel,Le
2021	07MEROM5 345 08DRESSR 345 1	HE,CIN	Rel
2022	08GIBSON 345 07MEROM5 345 1	HE,CIN	Rel
2023	07BLOMNG 345 08BLOOM 230 1	HE,CIN	Rel
2024	07NWTNVL 161 10NEWTVL 161	HE,SIGE	Rel
2025	07RATTS8 138 RATT TAP 138	HE,IPL	Rel
2026	10NEWTVL 161 14COLE 5 161	SIGE,BREC	Rel
2029	08HNTNGT 138 05HUNT J 138 1	CIN,AEP	Rel,Le
2030	08NOBLSV 345 05FALL C 345 1	CIN,AEP	Rel,Le
2032	08CAYSUB 345 05EUGENE 345	CIN,AEP	Rel,Le
2033	08NEWCAS 138 05FALL C 138 1	CIN,AEP	Rel,Le
2034	05GRNTWN 765 08GRNTWN 100 1	AEP,CIN	Rel,Le
2035	05GRNTWN 765 08GRNTWN 138 1	AEP,CIN	Rel,Le
2036	08EBEND 345 05STANNER 345 1	AEP,CIN	Rel,Le
2037	05STANNER 345 08M.FTHS 345 1	AEP,CIN	Rel,Le
2038	LAWRNCVL 138 08VIN 138 1	AMRN,CIN	Rel
2040	09STUART 345 08FOSTER 345 1	DPL,CIN	Rel
2041	09SUGRCK 345 08FOSTER 345 1	DPL,CIN	Rel
2042	07NAPOL8 138 08BATESV 138 1	HE,CIN	Rel
2043	07WORTH8 138 08HEOWEN 138	HE,CIN	Rel
2044	16PETE 138 08OKLND 138 1	IPL,CIN	Rel
2045	16PETE 138 08VIN J 138 1	IPL,CIN	Rel
2046	16PETE 345 08LOST R 345 1	IPL,CIN	Rel
2047	Gibson-Petersburg 345 flo Gibson-Bedford 345	IPL,CIN	Rel(OTDF),LODF
2048	16SUNNYS 345 08GWYNN 345 1	IPL,CIN	Rel
2049	12GHENT 345 08BATESV 345 1	LGEE,CIN	Rel
2050	08SPEED 345 12GHENT 345 1	LGEE,CIN	Rel
2051	11JEFFJC 138 08JEFF 138 1	LGEE,CIN	Rel
2052	Speed-Northside 138 flo Speed-Ghent 345	LGEE,CIN	Rel(OTDF),LODF
2053	Galagher-Paddys West 138 flo Jefferson-Rockport 765	LGEE,CIN	Rel(OTDF),LODF
2055	06PIERCE 345 08FOSTER 345 1	OVEC,CIN	Rel
2056	08GIBSON 345 ALBION 345 1	CIN,AMRN	Rel
2057	08M.FORT 345 09WMILTN 345 1	CIN,DPL	Rel
2058	09STUART 345 08ZIMER 345 1	CIN,DPL	Rel
2059	08BUFTN1 138 20BOONE 138 1	CIN,EKPC	Rel
2060	08BLOOM 230 07BLOMNG 345 1	CIN,HE	Rel
2061	08LINTON 138 07WORTH8 138 1	CIN,HE	Rel
2062	08FVEP2 138 16FVE_T 138 1	CIN,IPL	Rel

NERC FG #	FG Description	CA Owners	FG Type
2063	08WHITST 345 16GUION 345 1	CIN,IPL	Rel
2064	11GHENT 138 08FAIRW 138 1	CIN,LGEE	Rel
2068	06PIERCE 345 08BKJ135 138 1	CIN,OVEC	Rel
2069	08BUFTN1 345 06DEARB2 345 1	CIN,OVEC	Rel
2070	08BUFTN1 345 06PIERCE 345 1	CIN,OVEC	Rel
2071	08OKLND 138 10TOYOTA 138 1	CIN,SIGE	Rel
2072	New London-Webster 230 flo Greentown-Jefferson 765	CIN	Rel(OTDF),LODF
2073	FOSTER SUGERCREEK 345-STUART CLINTON 345	CIN,DPL	Rel(OTDF)
2074	09STUART 345 09CLINTO 345 1	DPL	Rel
2076	05HILLSB 138 09OHH 138 1	AEP,DPL	Rel
2077	10ABBRWW 138 14HENDR4 138 1	SIGE,BREC	Rel
2078	10CATO_T 138 CAT TAP 138	SIGE,IPL	Rel
2079	10TOYOTA 138 08OKLND 138 1	SIGE,CIN	Rel
2083	10CULLEY 138 10GRNDVW 138	SIGE	Rel
2084	10NE 138 10ELLIOT 138 1	SIGE	Rel
2085	10CULLEY 138 10ANGMND 138	SIGE	Rel
2086	10NEWTVL 161 10NEWTVL 138 1	SIGE	Rel
2087	10ABBRWN 138 10NE 138 1	SIGE	Rel
2088	10CULLEY 138 10DUBOIS 138 1	SIGE	Rel
2089	06CLIFTY 345 11TRIMBL 345 1	OVEC,LGEE	Rel
2092	11CLVRPR 138 12G R ST 138 1	LGEE	Rel
2093	11CLVRPR 138 12HARDBG 138 1	LGEE	Rel
2095	11CLVRPR 138 14N.HAR4 138 1	LGEE,BREC	Rel
2096	11BLUE L 161 20BLIT C 161 1 flo 06CLIFTY 345 11TRIMBL 345	LGEE,EKPC	Rel(OTDF),LODF
2097	11PADDYS 161 5SUMMER 161 1	LGEE,TVA	Rel,Com
2098	12GHENT 345 12GHENT 138 1	LGEE,CIN	Rel
2100	14COLE 5 161 14NATAL5 161 1	BREC	Rel
2102	14HOPCO5 161 5BARKLEY 161 1	BREC,TVA	Rel,Com
2103	16PETE 345 16THOMPS 345 1	IPL	Rel
2104	16PETE 345 16FRANCS 345 1	IPL	Rel
2105	16WHEAT 345 05BREED 345	IPL,AEP	Rel,Le
2106	16SUNNYS 345 05FALL C 345 1	IPL,AEP	Rel,Le
2107	16HANNA 345 05TANNER 345 1	IPL,AEP	Rel,Le
2130	20SPURLK 138 12KENTON 138 1	EKPC,LGEE	Rel
2131	Wylie Ridge-Sammis 345 kV line	PJM,FE	Rel,Le
2132	KRENDALE-SENECA 138 FLO WYLIE RIDGE-CABOT 500	PJM,FE	Rel(OTDF),LODF
2133	01BELMNT 500 05BELMON 765 1	PJM,AEP	Rel,Le
2134	Wylie Ridge-Tidd 345 kV line	PJM,AEP	Rel,Le
2135	01KAMMER 500 05KAMMER 765 1	PJM,AEP	Rel,Le
2137	01MITCHL 138 15ELRM 3 138 1	PJM,DLCO	Rel,Le
2141	02SAMMIS 345 15BVRVAL 345 1	FE,DLCO	Rel,Le

NERC FG #	FG Description	CA Owners	FG Type
2150	01DOUBS 500 8LOUDOUN 500 1	PJM,VAP	Rel,Le
2151	8MT STM 500 01DOUBS 500 1	VAP,PJM	Rel,Le
2181	Lemoyne-Fostoria 345 flo Bay Shore-Fostoria 345	FE,AEP	Rel(OTDF),LODF
2184	Bay Shore-Monroe 345 flo Lemoyne-Majestic 345	FE,MECS	Rel(OTDF),LODF
2185	LEMOYNE-MAJESTIC 345 flo BAY SHORE-MONROE 345	FE,MECS	Rel(OTDF),LODF
2186	Allen-Lulu 345	FE,MECS	Rel,Le
2187	12W LEXI 345 12W LEXI 138 1	LGEE	Rel
2188	12W LEXI 345 12BRWN N 345 1	LGEE	Rel
2189	12BRWN N 345 12BRWN N 138 1	LGEE	Rel
2190	12BRWN N 345 12ALCALD 345 1	LGEE	Rel
2191	12ALCALD 345 12ALCALD 161 1	LGEE	Rel
2192	11PINEV 500 11PINEVI 345	LGEE	Rel
2193	12POCKET 500 8PHIPP B 500 1	LGEE,TVA	Rel,Com
2194	14N.HAR4 138 14N.HAR5 161	BREC	Rel
2195	CENTRAL OHIO	AEP,DPL	Rel,Le
2196	Blue Lick 345/161 XFMR	LGEE	Rel
2197	Kyger-Sporn345 for Amos 765/345XFMR	OVEC,AEP	Rel(OTDF)
2198	Blue Lick 345/161 XFMR-Baker-Broadford	LGEE	Rel(OTDF)
2199	Ghent-W.Lexington 345kV-Baker-Broadford	LGEE	Rel(OTDF)
2200	Brown-Lebanon 138 kV	LGEE	Rel
2201	Brown South-Fawkes 138 kV	LGEE	Rel
2202	Kyger-Sporn345 for Baker-Broadford 765	OVEC,AEP	Rel(OTDF)
2203	BUFFINGTON_345_138_PIERCE_FOSTER_345	CIN, OVEC	Rel(OTDF),LODF
2209	W.Lex-E.W.Brown345 / Baker-Broadford765kv	LGEE	Rel(OTDF),LODF
2210	Knob Creek-Pond Creek 138 (flo) Baker-Broadord 765	LGEE	Reliability
2213	Wolf Lake-State Line 138 flo Dumont 765/345 Tr	NIPS,CE	Rel(OTDF),LODF
2214	Wolf Lake-State Line 138 flo Olive-UPNOR;RP 345	NIPS,CE	Rel(OTDF),LODF
2215	Wolf Lake-State Line 138 flo SLINE;5S-WASHI; R 138	NIPS,CE	Rel(OTDF),LODF
2216	New Carlisle-Trail Creek 138 flo Olive-Green Acre 345	NIPS,AEP	Rel(OTDF),LODF
2217	New Carlisle-Trail Creek 138 flo Olive-UPNOR:RP 345	NIPS,AEP	Rel(OTDF),LODF
2218	New Carlisle-Trail Creek 138 flo Dumont-Stillwell 345	NIPS,AEP	Rel(OTDF),LODF
2220	New Carlisle-Maple 138 flo Dumont-Stillwell 345	NIPS,AEP	Rel(OTDF),LODF
2221	Munster-Burnham 345 flo Olive-E. Fra 345	NIPS,CE	Rel(OTDF),LODF
2223	Dunont-Stillwell 345 flo Olive-Green Acre 345	NIPS,AEP	Rel(OTDF),LODF
2225	Deedsville-Leesburg 345 flo Dumont 345/138 Tr	NIPS,CIN	Rel(OTDF),LODF
2228	Hiple 345/138 Tr flo Goshen Jct-Hiple 138	NIPS	Rel(OTDF),LODF
2231	Laporte-Michigan City 138 flo Dumont-Stillwell 345	NIPS,AEP	Rel(OTDF),LODF
2232	Michigan City-Trail Creek 138 flo Olive-Green Acre 345	NIPS	Rel(OTDF),LODF
2233	Michigan City-Trail Creek 138 flo Dumont-Stillwell 345	NIPS	Rel(OTDF),LODF
2235	Tower Road 345/138 TR flo Schahfer 345/138 TR	NIPS	Rel(OTDF),LODF
2236	ALLEN-LULU 345 flo BAY SHORE-MONROE 345	FE,MECS	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
2237	BAY SHORE-TOUSSAINT 138 flo DAVIS BESSE-BEAVER 345	FE	Rel(OTDF),LODF
2238	GREENFIELD-LAKEVIEW 138 flo BEAVER-DAVIS BESSE 345	FE	Rel(OTDF),LODF
2239	LEMOYNE-FOSTORIA 345 flo BAY SHORE-FOSTORIA 345	FE,AEP	Rel(OTDF),LODF
2240	Toussaint-Ottawa 138 flo Davis Besse-Beaver 345	FE	Rel(OTDF),LODF
2241	MONROE-BAY SHORE 345 FLO LULU-ALLEN 345	MECS,FE	Rel(OTDF),LODF
2242	BAY SHORE 345/138 TR FLO LULU 3-TERMINAL LINE 3	FE	Rel(OTDF),LODF
2244	Paddys-Summershade 161 flo Baker-Broadford 765	LGEE,TVA	Rel(OTDF),LODF
2245	Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	LGEE,EKPC	Rel(OTDF),LODF
2246	Bay Shore-Monroe 345 flo Lemoyne-Davis Besse 345	FE,MECS	Rel(OTDF),LODF
2247	Beaver-Brookside 138 flo Beaver-Davis Besse 345	FE	Rel(OTDF),LODF
2248	Beaver-Davis Besse 345 flo Kammer-S Canton 765	FE	Rel(OTDF),LODF
2249	Brookside-Howard 138 flo Beaver-Davis Besse 345	FE,AEP	Rel(OTDF),LODF
2250	Hoyt-Maple 138 flo Sammis-Wylier 345	FE	Rel(OTDF),LODF
2251	Hoyt-Maple 138 flo Wylie Ridge-Cabot 500	FE	Rel(OTDF),LODF
2256	Mansfd-Highland 345 flo Mansfd-Hoytdl 345	FE	Rel(OTDF),LODF
2257	Mansfd-Bvrval 345 #2 flo Mansfd-Crescent 345	FE,DLCO	Rel(OTDF),LODF
2258	Richln-Ridgeville 138 flo Midw-Richln-Waus 138	FE	Rel(OTDF),LODF
2259	Sammis-Wylier 345 flo Kam-Har-FtM 3-Term line 500	FE,PJM	Rel(OTDF),LODF
2260	Sammis-Wylier 345 flo Kammer-S Canton 765	FE,PJM	Rel(OTDF),LODF
2261	Sammis-Wylier 345 flo Sammis-S Canton 345	FE,PJM	Rel(OTDF),LODF
2262	Sammis-Highland 345 flo Sammis-Bvrval 345	FE	Rel(OTDF),LODF
2263	Sammis-Star 345 flo S Canton-Star 345	FE	Rel(OTDF),LODF
2264	Star-Carlil 345 flo Avon-Juniper 345	FE	Rel(OTDF),LODF
2265	Star-Juniper 345 flo Hanna-Juniper 345	FE	Rel(OTDF),LODF
2266	Knob Creek-Pond Creek 138 (flo) Ghent-W. Lexington 345	LGEE	Rel(OTDF),LODF
2268	Smith - Green River Steel 138 (flo) Smith 345/138 Xfmr	LGEE	Rel(OTDF),LODF
2301	01BLACKO 500 01BEDNGT 500 1	PJM	Rel,Le
2303	01HATFLD 500 01BLACKO 500 1	PJM	Rel,Le
2304	01HATFLD 500 01YUKON 500 1	PJM	Rel,Le
2305	01WYLIER 500 O1CABOT 500 1	PJM	Rel,Le
2306	Wylie Ridge #5 500/345 kV xfmr	PJM	Rel,Le
2307	Wylie Ridge #7 500/345 kV xfmr	PJM	Rel,Le
2309	15COLLIE 138 15ELWYN 138 1	DLCO	Rel
2314	DAVIS BESSE-BAY SHORE 345 flo DAVIS BESSE-LEMOYNE 345	FE	Rel(OTDF),LODF
2315	DAVIS BESSE-LEMOYNE 345 flo DAVIS BESSE-BAY SHORE 345	FE	Rel(OTDF),LODF
2316	ALLEN 345/138 Tr flo MONROE-BAY SHORE 345	FE	Rel(OTDF),LODF
2317	Bay Shore 345/138kV Tr	FE	Rel,Le
2325	8POSSUM 500 BURCHES 500 1	VAP,PJM	Com,Le
2336	BentnHrbr-Palisades345/Cook-Palisades345	AEP,MECS	Rel(OTDF),Le,LODF
2337	Cook-Palisades345/BentnHrbr-Palisades345	AEP,MECS	Rel(OTDF),Le,LODF

NERC FG #	FG Description	CA Owners	FG Type
2338	Cook-Palisades345/TwinBranch-Argenta345	MECS,AEP	Rel(OTDF),LODF
2339	BentnHrbr-Palisades345/TwinBranch-Argenta345	MECS,AEP	Rel(OTDF),LODF
2340	TwinBranch-Argenta345/Cook-Palisades345	MECS,AEP	Rel(OTDF),LODF
2341	TwinBranch-Argenta345/Robison Pk-Argenta 345	MECS,AEP	Rel(OTDF),LODF
2350	BELMNT500/765TX-KAMMER500/765TX	PJM,AEP	Rel(OTDF),Le
2351	KAMMER500/765TX-BELMNT500/765TX	PJM,AEP	Rel(OTDF),MRD,Le
2352	PRNTY-MTSTM500/BLACKO-BEDNGT500	PJM,VAP	Rel(OTDF),MRD,Le
2353	BLACKO-BEDNGT500-PRNTY-MTSTM500	PJM	Rel(OTDF),MRD,Le
2356	PRNTY-MTSTM500-HATFIELD-BLACKO500	PJM,VAP	Rel(OTDF),Le
2357	Wylie Ridge #7 500/345 xfmr l/o Wylie Ridge #5 500/345 xfmr	PJM	Rel(OTDF),Le
2358	Wylie Ridge #5 500/345 xfmr l/o Wylie Ridge #7 500/345 xfmr	PJM	Rel(OTDF),Le
2362	BLACKO-BEDNGT500/MT STM-DOUBS 500	PJM	Rel(OTDF),Le
2363	MT STM-MDWBRK500/MT STM-DOUBS500	PJM,VAP	Rel(OTDF),Le
2365	FT MARTN-PRNTY500/HARRSN-PRUNTY500	PJM	Rel(OTDF),Le
2366	MITCH-ELRAMA138/SAMMIS-WYLIER345	PJM,DLCO	Rel(OTDF),Le
2367	MITCH-ELRAMA138/WYLIER-CABOT500	PJM,DLCO	Rel(OTDF),Le
2368	SAMMIS-WYLIE RIDGE 345 FLO KAMMER 765/345 TR	PJM,FE	Rel(OTDF),LODF
2369	Tidd-Wylie Ridge 345 kV line l/o Kammer 765/500 kV xfmr	PJM,AEP	Rel(OTDF),Le
2370	BEDINGTON-DOUBS500/PRUNTY-MT STM500	PJM	Rel(OTDF),Le
2371	Wylie Ridge #7 500/345 xfmr l/o Kammer 765/500 kV xfmr	PJM	Rel(OTDF),Le
2372	Wylie Ridge #7 500/345 xfmr l/o Harrison-Wylie Ridge 500 kV	PJM	Rel(OTDF),Le
2373	Wylie Ridge #7 500/345 xfmr l/o Belmont-Harrison 500 kV	PJM	Rel(OTDF),Le
2374	Wylie Ridge #5 500/345 xfmr l/o Harrison-Wylie Ridge 500 kV	PJM	Rel(OTDF),Le
2375	Wylie Ridge #5 500/345 xfmr l/o Belmont-Harrison 500 kV	PJM	Rel(OTDF),Le
2376	PRNTY-MTSTM500/BEDINGTON-DOUBS500	PJM,VAP	Rel(OTDF),Le
2400	DUMONT765-345TX-COOK765-345TX	AEP	Rel(OTDF),Le,MRD
2401	DUMONT765/345TX-DUMONT WILTON C 765	CE,AEP	Rel(OTDF),Le
2402	COOK765-345TX-DUMONT765-345TX	AEP	Rel(OTDF),Le,MRD
2403	KANAWZ-M FUNK 345/BAKER-BROADFORD 765	AEP	Rel(OTDF),MRD,Le
2405	Kammer-W Belair 345/Kammer-S Canton 765	AEP	Rel(OTDF)
2406	CLVRDL-LXNGTN500/PRUNTYTN-MT STM500	AEP,VAP	Rel(OTDF)
2407	CLVRDL-LXNGTN500/MTSTM-VLY500&VLY500-230	AEP,VAP	Rel(OTDF)
2408	KANAWZ-M FUNK 345/PRUNTYTN-MT STM500	AEP	Rel(OTDF)
2410	KANAWZ-M FUNK 345/MTSTM-VLY500&VLY500-230	AEP	Rel(OTDF)
2411	Muskingum River-Ohio Central 345 kv / Kammer-S. Canton 765 kv ckt	AEP	Rel(OTDF),LODF
2412	Waterford-Muskingum 345 kv / Mountaineer-Belmont 765 kv	AEP	Rel(OTDF),LODF
2413	S. Canton 765/345 kv Xfmr / Tidd-Canton Central 345 kv	AEP	Rel(OTDF),LODF
2414	S. Canton 765/345 kv Xfmr / Marysvl 765/345 kV Xfmr	AEP	Rel(OTDF),LODF
2415	S. Canton 765/345 kV Xfmr / Kammer 765/500 kV Xfmr	AEP	Rel(OTDF),LODF
2416	Muskingum River-Ohio Central 345 kV / E Lima-Fostoria 345 kV	AEP	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
2417	J Ferry-Antioch 500kV / Broadford-Sullivan 500 kV	AEP,DUK	Rel(OTDF),LODF
2420	COLEMN-NATAL 161/WILSN-GRN RVR 161	BREC,LGEE	Rel(OTDF)
2421	HOPKIN CO-BARKLEY 161/WILSN-GRN RVR 161	BREC,TVA,LGEE	Rel(OTDF)
2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	BREC	Rel(OTDF)
2423	Hardinsburg-Paradise 161 kV	BREC,TVA	Rel
2450	GALLAGHER 230/138 XFMR	CIN	Rel
2452	08SPEED 345/138 11GHENT 345 11W LEXN 345	CIN	Rel(OTDF)
2453	08GALAGH 230/138 08GALAGH 08PUMPCT 230	CIN	Rel(OTDF)
2454	08S CRK 345 CAY CT 345 08WHEAT AMO 345	CIN	Rel(OTDF),LODF
2455	Gibson 345/138	CIN	Rel
2456	Gibson 345/138 Gibson Pete 345	CIN	Rel(OTDF)
2457	Cayuga 345/230	CIN	Rel
2458	Cayuga 345/230 Cayuga Nucor 345	CIN	Rel(OTDF)
2459	08CAYUGA NUCOR 345 08CAYSUB 05EUGEN 345	CIN	Rel(OTDF)
2460	08CAYUGA VDSBRG 230 08CAYUGA FRNKFT 230	CIN	Rel(OTDF)
2461	08GIBSON WHEAT 345 08GIBSON 16PETE 345	CIN	Rel(OTDF)
2462	08WHEAT QUALTC 345 08GIBSON 16PETE 345	CIN	Rel(OTDF)
2464	Frankfort-New London 230 flo Veedersburg-Cayuga 230	CIN	Rel(OTDF),LODF
2465	Speed-Ramsey 345 Buckner - Middletown 345	CIN	Rel(OTDF),LODF
2466	Zimmer to Port Union 345 kV	CIN	Rel
2481	11TRIMBL 345 11TRIMBL 138	LGEE	Rel(OTDF),LODF
2483	Avon - Loudon 138 kV	EKPC,LGEE	Rel
2484	Northside-Clify Creek 138 (flo) Trimble Co.-Clifty Creek 345	LGEE,OVEC	Rel(OTDF),LODF
2485	Galagher-Paddys West 138 (flo) Trimble Co.-Clifty Creek 345	LGEE,CIN	Rel(OTDF),LODF
2486	Speed-Northside 138 (flo) Trimble Co.-Clifty Creek 345	LGEE,CIN	Rel(OTDF),LODF
2487	Ghent 345/138 Tr flo of Ghent-Batesville 345	LGEE	Rel(OTDF),LODF
2488	11BLUE L 161 20BLIT C 161 1 flo 11GHENT 345 11W LEXN 345	LGEE,EKPC	Rel(OTDF),LODF
2500	10NEWTVL-11CLVRPR 138/COLEMN-NATAL 161	SIGE,LGEE	Rel(OTDF)
2501	Ghent 345/138 Xfmr for loss of Ghent-W. Lexington 345	LGEE	Rel(OTDF),LODF
2551	Petersburg 345/138 xfmr (East)	IPL	Rel(OTDF),LODF
2853	19001 CVTRY 345-120/MADRD-MAJTC	MECS	Rel(OTDF),LODF
2854	CVTRY 345-120/BRSTNN-MON34	MECS	Rel(OTDF),LODF
2855	BNSTNS-MON12/MON12-WAYNE	MECS	Rel(OTDF),LODF
2856	MON12-WAYNE/BNSTNS-MON12	MECS	Rel(OTDF),LODF
2859	BAYSHORE-MONROE 345 FLO ALLEN-LULU 345, LULU-MAJESTIC 345, & LULU-MONROE 345	MECS,FE	Rel(OTDF),LODF
2861	Monroe-Bay Shore 345 flo Bay Shore-Fostoria 345	MECS,FE	Rel(OTDF),LODF
3001	WEMPLETOWN-PADDOCK 345 KV	CE,ALTE	Rel
3002	NELSON-DEWEY 161/138 XFMR	ALTE	Rel
3003	COLUMBIA-S. FOND DU LAC 345 KV	ALTE	Rel
3004	COLUMBIA-N. MADISON 345 KV	ALTE,MGE	Rel
3005	S. FOND DU LAC-FITZGERALD 345 KV	ALTE,WPS	Rel

NERC FG #	FG Description	CA Owners	FG Type
3006	EAU CLAIRE-ARPIN 345 KV	ALTE,NSP,WEC,WPS	Rel,MRD
3007	ELLINWOOD-AVIATION 138 KV	WPS	Rel
3009	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK	NSP,ALTE,WEC,WPS	Rel(OTDF)
3010	ROCKDALE 345/138 XFMR 1	ALTE	Rel
3011	PADDOCK 345/138 XFMR 1	ALTE	Rel
3012	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	ALTE	Rel(OTDF)
3013	ROCKDALE XFMR 1 + ROCKDALE XFMR 2	ALTE	Rel(OTDF)
3014	ROCKDALE XFMR 2 + PADDOCK XFMR	ALTE	Rel(OTDF)
3015	NELSON DEWEY XFMR+WMPLETOWN-PADDOCK	ALTE	Rel(OTDF)
3016	NELSON DEWEY XFMR + ECL-ARP+Guide	ALTE	Rel(OTDF)
3017	Cassvl-NED 161 for Wemp-Paddock 345	ALTE,DPC	Rel(OTDF)
3018	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON	ALTE,WPS,WEC,NSP	Rel(OTDF)
3020	Rockdale Xfmr 1 for Paddock Xfmr	ALTE	Inform,Rel(OTDF)
3021	PADDOCK-BLACKHAWK X53 PADDOCK-ROCK RIVER X39	ALTE	Rel(OTDF),LODF
3022	X59 Christiana-Kegonsa 138 for Columbia-N Madison 345	ALTE	Rel(OTDF)
3023	ROE-Lkhd 138 for EauClair-Arp, Wien-Tcorners	ALTE	Rel(OTDF)
3024	Blackhwk-Cor X54 for Paddock-ROR X39 138	ALTE	Rel(OTDF)
3025	Russel-Rockdale 138/Paddock-Rockdale 345	ALTE	Rel(OTDF),LODF
3026	Rockdale TR2 for Rockdale TR 1	ALTE	Rel,OTDF,LODF
3027	Burlington-N Lk Geneva Tp flo Wempltown-Paddock	ALTE	Rel(OTDF),LODF
3028	Sand Lk-P Edwards 138 for N.Appl-Ror 345	ALTE	Rel(OTDF)
3029	Green Lk-Roeder 138kV	ALTE	Rel
3030	Green Lk-Roeder 138 for N Appleton-RoR 345	ALTE	Rel(OTDF)
3031	X59 Christiana-Kegonsa 138 for F1 Christiana-Fitchburg 138	ALTE	Rel(OTDF)
3032	ROCKY RUN -NORTHPT+WESTON-ROCKY RUN	WPS	Rel(OTDF),Cont,LODF
3033	Arpin Xformer+Arpin-Rocky Run 345	ALTE	Rel (OTDF), LODF
3034	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	ALTE	Rel(OTDF),LODF
3035	Columbia-Portage138 FLO Columbia-Portage138 ckt2	ALTE	Rel(OTDF),LODF
3036	Columbia-Portage138 ckt2 FLO Columbia-Portage138	ALTE	Rel(OTDF),LODF
3037	Edgewater-S.SheboygnFls138 FLO Edgwtr-S.FndDuLac138	ALTE	Rel(OTDF),LODF
3038	Paddock-RockRiver 345-138 T3 FLO Paddock-Blkhwk138	ALTE	Rel(OTDF),LODF
3039	Rockdale 345-138 T1 FLO Rockdale 345-138 T3	ALTE	Rel(OTDF),LODF
3040	Rockdale 345-138 T2 FLO Rockdale 345-138 T3	ALTE	Rel(OTDF),LODF
3041	Columbia-N.Madison138 FLO Columbia-NMA345	ALTE, MGE	Rel(OTDF),LODF
3042	Rock River-Janesville 138 flo Paddock-Rockdale 345	ALTE	Rel(OTDF),LODF
3043	Rock River-Janesville 138 (flo) Rock River-Viking 138	ALTE	Rel(OTDF),LODF
3044	Rockdale 345/138 Xfmr 3 (flo) Paddock 345/138 Xfmr	ALTE	Rel(OTDF),LODF
3045	Portage - Hamilton 138 (flo) Columbia - South Fond du Lac 345	ALTE	Rel(OTDF),LODF
3046	Rock River - Janesville 138 (flo) Rockdale 345/138 Xfmr 3	ALTE	Rel(OTDF),LODF
3102	BLAND-FRANKS 345 KV	AMRN,AECI	Rel

NERC FG #	FG Description	CA Owners	FG Type
3103	CAHOKIA 345/138 XFMR 8	AMRN	Rel
3104	CAHOKIA 345/138 XFMR 9	AMRN	Rel
3105	JOPPA-CAPE GIRARDEAU 161 KV	AMRN,EEI	Rel
3106	MASON 345/138 XFMR 2	AMRN	Rel
3107	MONTGOMERY-SPENCER 345 KV	AMRN	Rel
3108	OVERTON-SIBLEY 345 KV	AMRN,MPS	Rel
3109	RUSH ISLAND-ST FRANCOIS 345 KV	AMRN	Rel
3110	QUINCY S-QUINCY E 138	AMRN	Rel
3111	XENIA -MT VERNON 345 KV	IP,AMRN	Rel
3112	DUCK CREEK-IPAVA 345 kV	AMRN,CILC	Rel
3113	NEWTON-CASEY 345 KV	AMRN	Rel
3114	BREED-CASEY 345 KV	AMRN,AEP	Rel
3115	COFFEEN-PANA 345 KV	AMRN	Rel
3116	ALBION 345/138 XFMR	AMRN	Rel
3117	Bland-Franks345 + Rush-St Francios + TR	AMRN,AECI	Rel(OTDF),MRD
3118	ALBION-XFMR + BREED-CASEY	AMRN	Rel(OTDF)
3120	COFFEEN-PANA+MONTGMRY-SPENCER	AMRN	Rel(OTDF)
3121	ALBION XFMR + GIBSON-PETERSBURG	AMRN	Rel(OTDF)
3122	ALBION XFMR + DUMONT-WILTON CENTER	AMRN	Rel(OTDF)
3123	COFFEEN-PANA+DUMONT-WILTON CENTER	AMRN	Rel(OTDF)
3124	JOPPA-CAPE GIRARDEAU+SHAWNEE-KELSO	AMRN,EEI	Rel(OTDF)
3125	SIDNEY-RANTOUL + SIDNEY-MIRA TAP	AMRN	Rel(OTDF)
3126	SIDNEY-RANTOUL + COFFEEN-PANA-KINCAID	AMRN	Rel(OTDF)
3127	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID	AMRN	Rel(OTDF)
3128	S QUINCY-E QUINCY+QUINCY S-QUINC E	AMRN	Rel(OTDF)
3129	MASON XFMR #3 + MASON XFMR #2	AMRN	Rel(OTDF)
3130	ST FRANC XFMR+ST FRANC-LUTESVILLE	AMRN	Rel(OTDF)
3131	PAWNE-AUBURN+KINCAID-LATHM	AMRN	Rel(OTDF)
3132	MURDOCK-SIDNEY + SIDNEY XFMR	AMRN	Rel(OTDF)
3133	LABADIE-MASON3 + LABADIE-MASON4	AMRN	Rel(OTDF)
3134	MISS TAP-ROXFRD1+MISS TAP ROXFRD 3	AMRN	Rel(OTDF)
3135	ALBION-CROSSVL + XENIA-MT VERNON	AMRN	Rel(OTDF)
3138	MONTGMRY-GUTHRIE+MONTGMRY MCCREDIE	AMRN	Rel(OTDF)
3139	PAWNEE WEST XFMR + PANA-KINCAID	AMRN	Rel(OTDF)
3140	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID	AMRN	Rel(OTDF)
3141	MIS TAP3-ROXFRD + MIS TAP1-ROXFORD	AMRN	Rel(OTDF)
3142	RAMSEY-PANA + COFFEEN-PANA-KINCAID	AMRN	Rel(OTDF)
3143	CAHOKIA XFMR 9 + CAHOKIA XFMR 8	AMRN	Rel(OTDF)
3144	RUSH-ST FRANCOIS + BLANDS-FRANKS	AMRN	Rel(OTDF)
3145	PANA XFMR + COFFEEN-COFFEEN NORTH	AMRN	Rel(OTDF)
3146	MEREDOSIA-IND PARK+DUCK CRK-TAZEWL	AMRN,IP	Rel(OTDF)

NERC FG #	FG Description	CA Owners	FG Type
3147	MASON CTY-MT PLSKI FOR DUCK CRK-TAZEWL	AMRN,IP	Rel(OTDF)
3148	SIOUX-MISS TAP3+SIOUX-MISS TAP1	AMRN	Rel(OTDF)
3149	SIOUX-MISS TAP3	AMRN	Rel
3150	Newton 345/138 #2 for Newt-Casey345	AMRN	Rel(OTDF)
3152	Meremac-St.Francois1Meremac-St.Francois2	AMRN	Rel(OTDF)
3153	Clark Xfmr Bland-Franks	AMRN	Rel(OTDF)
3154	Meremac-St.Francois Bland-Franks	AMRN	Rel(OTDF)
3155	Lutsvle-Essx-NMadrid for loss of Bland Franks	AMRN	Rel(OTDF)
3157	McCredie-Overton345 for Bland-Franks 345	AMRN	Rel(OTDF)
3159	Neoga-Holland-Ramsey 345 Bland-Franks 345	AMRN	Rel,LODF
3160	Bland-Franks 345 for McCred-Overton 345	AECI,AMRN	Rel(OTDF),LODF
3201	11215 DUMONT-WILTON 765KV(AEP-CE)	CE,AEP	Rel
3202	17723 BURNHAM-TAYLOR 345KV	CE	Rel
3203	10802 LOCKPORT-LISLE 345 KV RED	CE	Rel
3204	10801 LOCKPORT-LISLE 345 KV BLUE	CE	Rel
3205	16703 PLANO- ELECT JCT 345 KV RED	CE	Rel
3206	16704 PLANO-ELECT JCT 345 KV BLUE	CE	Rel
3207	TSS116 GOODINGS GR 345KV RED BUSTIE	CE	Rel
3210	10802 Lock-LisR for 10801Lock-LiB+G	CE	Rel(OTDF)
3211	10801 Lock-LisB for 10802Lock-LiR+G	CE	Rel(OTDF)
3212	10802 Lock-Lisl R for 16703 PL-EJ R	CE	Rel(OTDF)
3213	10801 Lock-Lisl B for 16704 PL-EJ B	CE	Rel(OTDF)
3214	10322 Lis-LomR for 10321 Lis-LomB+G	CE	Rel(OTDF)
3215	10321 Lis-LomB for 10322 Lis-LomR+G	CE	Rel(OTDF)
3216	0621 Byron-ChV B for 0622 Byr-ChV R	CE	Rel(OTDF)
3217	0621 Byron-ChV B for 0624 Byr-Wemp	CE	Rel(OTDF)
3218	0622 Byron-ChV R for 0621 Byr-ChV B	CE	Rel(OTDF)
3219	0622 Byr-ChV Red for 0624 Byr-Wemp	CE	Rel(OTDF)
3220	16704 Plan-EJ B for 16703 Plan-EJ R	CE	Rel(OTDF)
3221	16703 Plan-EJ Red for 16704 Pl-EJ B	CE	Rel(OTDF)
3222	11601 EFrk-GoodiB for 11602 EF-GG R	CE	Rel(OTDF)
3223	11602 EFrk-GoodiR for 11601 EF-GG B	CE	Rel(OTDF)
3227	0404 Quad-H471 for 15503 Cordo-Nelson	CE	Rel(OTDF)
3228	0403 Quad-Cord-Nelson for 0404 Quad-H471	CE	Rel(OTDF)
3229	11604 Goodi-LockR for 11617GG-LockB	CE	Rel(OTDF)
3230	11617 Goodi-LockB for 11604GG-LockR	CE	Rel(OTDF)
3231	GOODI 345R BT for 1223Dres-EJ B+T83	CE	Rel(OTDF)
3232	11120 EJ-W407 for 10802 Lock-LiR +G	CE	Rel(OTDF)
3233	11124 EJ-Lomb for 10801 Lock-LiB +G	CE	Rel(OTDF)
3234	2102 Kincaid-Lath for 11215 Dum-Wlt	CE	Rel(OTDF)
3235	2101 Kinc-BrokTp for 11215 Dum-Wilt	CE	Rel(OTDF)

NERC FG #	FG Description	CA Owners	FG Type
3236	17101 Wemp-Pad for 9922 Zion-Arcad	CE,ALTE	Rel(OTDF)
3237	17101 Wemp-Pad for 2221 Zion-PlsPr	CE,ALTE	Rel(OTDF)
3238	17101 Wemp-Pad for 15616 ChV-Silver	CE,ALTE	Rel(OTDF)
3239	17101 Wemp-Pad for Arpin-ÉauClar +G	CE,ALTE	Rel(OTDF)
3240	2221 Zion-PlsPr for 9922 Zion-Arcd	CE,WEC	Rel(OTDF)
3241	2221 Zion-PlsP for 17101 Wemp-Pad	CE,WEC	Rel(OTDF)
3242	9922 Zion-Arcad for 2221 Zion-PlsP	CE,WEC	Rel(OTDF)
3243	9922 Zion-Arcad for 17101 Wemp-Pad	CE,WEC	Rel(OTDF)
3245	15616 Cher-Silv for 15502 Nels-EJ	CE	Rel(OTDF)
3250	15502 Nels-EJ for 15616 Cher-Silv	CE	Rel(OTDF)
3251	0404 Quad Cities - NWS&W (H471)	CE	Rel
3252	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81	CE	Rel(OTDF)
3253	Kewanee(CE)-Kewanee(IP) 138 BT	CE	Rel
3255	Kewanee(CE)-Kewanee(IP) 138 BT	CE	Rel
3257	Quad City-SUB 91 345 KV	CE,MEC	Rel,Com
3258	Quad City-Rock Creek (FLO) QC-SUB91	CE,ALTW,MEC	Rel(OTDF),Com
3259	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV	CE,MEC	Rel(OTDF)
3260	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345	CE	Rel(OTDF),LODF
3261	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345	CE	Rel(OTDF)
3301	TAZEWELL - MASON 138 KV	CILC	Rel
3302	HOLLAND - E SPRINGFIELD 138 KV	CILC	Rel
3303	E SPRINGFIELD-EASTDALE 138 KV	CILC,CWLP	Rel
3304	TAZEWELL-POWERTON 345 KV	CILC,CE	Rel
3306	Holland-Mason138+Duck Creek-Tazewell345	CILC	Rel(OTDF)
3350	Renshaw-Livingston 161 for Joppa-Kelso 345	SIPC	Rel(OTDF)
3401	SIDNEY XFMR + BUNSONVILLE XFMR	IP	Rel(OTDF)
3402	CAHOKIA-BALDWIN+COFFEEN-ROXFRD TAP	AMRN,IP	Rel(OTDF)
3403	SIDNEY-MIRA TAP + SIDNEY-SW CAMPUS	IP	Rel(OTDF)
3404	STALLINGS XFMR+COFFEEN-ROXFORD TAP	IP	Rel(OTDF)
3405	BUNSONVILLE-EUGENE + BREED-CASEY	IP,AEP	Rel(OTDF)
3406	CAHOKIA-BALDWIN+ROXFD TP-STALLING	AMRN,IP	Rel(OTDF)
3407	STALLING XFMR + ROXFORD-STALLINGS	IP	Rel(OTDF)
3408	PANA-MOWEAQ T + KINCAID-LATHAM	IP	Rel(OTDF)
3409	PANA-MOWEAQ T + PONTIAC-LATHAM	IP	Rel(OTDF)
3410	SIDNEY XFMR + DUMONT-WILTON	IP	Rel(OTDF)
3411	SIDNEY-MIRA + SIDNEY-RANTOUL	IP	Rel(OTDF)
3412	FAYET-TILDEN + BALDWN-MT VR345/138	IP	Rel(OTDF)
3413	COFFN-ROXFD IP FOR XENIA-MT VRNON	AMRN,IP	Rel(OTDF)
3414	COFFN-ROXFD IP FOR COFFN N-COFFN	AMRN,IP	Rel(OTDF)
3416	COFFEEN-ROXFORD 345	IP	Rel
3418	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765	IP	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
3419	Xenia-MtVernon 345 for Coffeen-Roxfd 345	IP,AMRN	Rel(OTDF)
3420	Coffeen-Roxford Jefferson-Rockport	IP	Rel(OTDF)
3421	Rush Isl-St Francios 345 for Franks-Salem 345	AMRN	Rel(OTDF),LODF
3422	Rush Isl-St Francios345 for Mt Vern-Wfrank345	AMRN	Rel(OTDF)
3423	Bland-Franks 345 for Lutes-Essx345,Kelso Guid	AMRN	Rel(OTDF)
3424	Salem-W Mt Vernon Xenia-W MT Vernon	IP	Rel(OTDF)
3425	Gillespie-Lacleed Tap 138 + Xenia-MtVern 345	IP	Rel(OTDF)
3426	Baldwin-Cahokia 345 for Baldw-Stallings,Stal TR	IP	Rel(OTDF)
3501	Whitewater-Mukwonago 138 flo King-Arpin 345 kV	WEC	Rel(OTDF),LODF
3502	OAK CREEK 345/230 XFMR	WEC	Rel
3503	ALBERS-PARIS 138 KV	WEC	Rel
3504	PARIS-ST MARTINS 138 KV	WEC	Rel
3505	FREDONIA-Cedarsauk 138 KV	WEC	Rel
3507	EDGEWATER-Cedarsauk-Granville 345 KV	ALTE,WEC	Rel
3508	BLUEMOUND-TOSA-W 138 KV	WEC	Rel
3509	MUR 138-MULLET RVR 138 KV	ALTE,WEC	Rel
3510	CONCORD-COONEY 138 KV	WEC	Rel
3511	MUKWONAGO-ST MARTINS 138 KV	WEC	Rel
3512	LS - WHITEWATER 138 KV	WEC	Rel
3513	NLK GENEVA TAP-SUGAR CR 138 KV	WEC	Rel
3514	NORDIC-PERCH LAKE 138 KV	WEC,UPPC	Rel
3515	JEFFERSON-LAKEHEAD 138 KV	WEC	Rel
3517	ARCADIAN-GRANVILE 345 KV	WEC	Rel
3518	BUTLER-GRANVILE+ARCADIAN-GRANVILE	WEC	Rel(OTDF)
3519	BUTLER-GRANVILE+WEMPLETOWN-PADDOCK	WEC	Rel(OTDF)
3520	Merril-Hil 138 for Wemp-Paddock 345	WEC	Rel(OTDF)
3521	Manistique-Hiawatha	WEC	Rel
3522	Albers-Paris138 for Wemp-Padock 345	WEC	Rel(OTDF)
3523	Stiles-Pioneer 138 for N.Appl-WhiteClay138	WEC	Rel(OTDF),LODF
3524	Ellington-Hintz + N.Appleton-Rocky Run 345	WEC	Rel(OTDF)
3525	Stiles-Amberg 138 for Morgan-Plains 345	WEC	Rel(OTDF)
3527	PleasPr-Racine 345 for Wemp-Pad 345	WEC	Rel,OTDF,LODF
3528	N Appleton-Wh Clay 138 for Stiles-Pulliam 138	WEC	Rel(OTDF)
3529	N. Appleton-Rocky Run 345kV	WEC	Rel
3530	Jeffrsn-LakehdCam138 Col-SFL345	WEC	Rel(OTDF),LODF
3531	WhtWater-Mukwanago138 Roe-Jeff138	WEC	Rel(OTDF),LODF
3532	Ellington-Hintz 138 for N.Appleton-Rocky Run 345	WEC	Rel(OTDF),LODF
3533	Whitewater-Mukwonago 138 for SFL-Columbia 345	WEC	Rel(OTDF),LODF
3534	Kenosha-Albers 138 for Wempletown-Paddock 345	WEC	Rel(OTDF),LODF
3535	N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR	WEC	Rel(OTDF),LODF
3536	N.Appleton 345/138 T1 for N.Appleton 345/138 T3	WEC	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
3537	Kenosha-Lakeview 138 for PleasPr-Zion 345	WEC	Rel(OTDF)
3538	STILES4-PULLIAM 138+STILES5-PULLIAM 138	WEC,WPS	Rel (OTDF), LODF
3539	VALLEY-HAYMKT 138+GRANVL1-ARCADN1 345	WEC	Rel (OTDF), LODF
3540	VALLEY-HAYMKT 138+BLUMND3-OC CRK7 230	WEC	Rel (OTDF), LODF
3541	VALLEY-HAYMKT 138+BLUMND5-OCONNR-6 138	WEC	Rel (OTDF), LODF
3542	Amberg-Plains 138 flo Morgan-Plains 345	WEC	Rel(OTDF),LODF
3543	Granville-Swan 138 flo Saukville 345/138 Tr 1	WEC	Rel(OTDF),LODF
3544	Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345	WEC	Rel(OTDF)
3545	Amberg-Plains138 FLO Now Tap-Amberg138	WEC	Rel(OTDF),LODF
3546	Cedar-National138 FLO Cedar-Tilden138	UPPC, WEC	Rel(OTDF),LODF
3547	Granville 345-138 Xfr FLO Wempletown-Paddock345	WEC	Rel(OTDF),LODF
3548	Lakehead-Haiwatha 138kV	WEC	Rel
3549	N.Appleton-LostDauphin138 FLO E.Krok-Kewaunee138	WEC	Rel(OTDF),LODF
3550	N.Appleton-WhiteClay138 FLO Stiles-Pulliam138	WEC	Rel(OTDF),LODF
3551	N.Appleton 345-138 T1 FLO N.Appleton 345-138 T2	WEC	Rel(OTDF),LODF
3552	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T1	WEC	Rel(OTDF),LODF
3553	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T3	WEC	Rel(OTDF),LODF
3554	N.Appleton 345-138 T3 FLO N.Appleton 345-138 T2	WEC	Rel(OTDF),LODF
3555	Plains-Amberg138 FLO Now Tap-Amberg138	WEC	Rel(OTDF),LODF
3556	Plains-Amberg138 FLO Morgan-Plains345	WEC	Rel(OTDF),LODF
3557	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345	WEC	Rel(OTDF),LODF
3558	PleasPrairie-Arcadian345 FLO Zion-Arcanian345	WEC	Rel(OTDF),LODF
3559	Stiles-Crivitz115 FLO Morgan-Plains345	WEC	Rel(OTDF),LODF
3560	Whitewater-Mukwonago FLO CherryVal-SilvrLk345	WEC	Rel(OTDF),LODF
3561	Whitewater-Mukwonago138 FLO University-SugarCr138	WEC	Rel(OTDF),LODF
3562	McGulpin-Straits138 ckt. 3 FLO ckt. 1	WEC,MECS	Rel(OTDF),LODF
3563	N.Appleton-LostDauphin138 FLO N.Appleton-Mason St138	WEC, WPS	Rel(OTDF),LODF
3564	McGulpin-Straits138 ckt. 1 FLO ckt. 3	WEC,MECS	Rel(OTDF),LODF
3565	Paris-Burlington 138 (flo) Wempletown-Paddock 345	WEC	Rel(OTDF),LODF
3601	ARPIN - ROCKY RUN 345 KV	ALTE,WPS	Rel
3602	ROCKY RUN - N APPLETON 345 KV	WPS,WEC	Rel
3604	N FOND DU LAC-AVIATION 138 KV	WPS,ALTE	Rel
3605	MASON ST - N APPLETON 138 KV	WPS,WEC	Rel
3607	HIGHWAYV - PREBLE 138 KV	WPS	Rel
3608	WHITING AVE. - HOOVER 115 KV	WPS	Rel
3609	ROCKY RUN-WESTON 345 KV	WPS	Rel
3611	KEWAUNEE 345/138 XFMR	WPS	Rel
3612	N APPLETON-FITZGERALD 345KV	WEC,WPS	Rel
3613	KEWAUNEE XFMR+KEWAUNEE-N APPLETON	WPS	Rel(OTDF)
3614	ROCKY RUN-WHITING AVE 115KV	WPS	Rel
3615	ROCKY RUN-NORTHPT 115KV	WPS	Rel

NERC FG #	FG Description	CA Owners	FG Type
3616	WESTON-KELLY 115KV	WPS	Rel
3617	HIGHWAYV-PREBLE+N APPLTN-WHITE CLAY	WPS	Rel(OTDF)
3618	HIGHWAYV-PREBLE+N APPLTN-MASON ST	WPS	Rel(OTDF)
3619	Kewaunee 345/138 for PtBeach-N.Appleton 345	WPS	Rel(OTDF)
3620	RockyRun-Whiting115 FLO N.Appleton-RockyRun345	WPS	Rel(OTDF),LODF
3621	Whiting-Hoover115 FLO N.Appleton-RockyRun345	WPS	Rel(OTDF),LODF
3622	Weston 345-115 T1 FLO RockyRun 345-115 T1	WPS	Rel(OTDF),LODF
3623	Kewaunee-N.Appleton xfmr FLO N.Appleton-PtBeach345	WPS, WEC	Rel(OTDF),LODF
3624	Kewaunee-PtBeach345 FLO N.Appleton-PtBeach345	WPS, WEC	Rel(OTDF),LODF
3625	Cranberry Loop 115kV	WPS, ALTE	Rel
3626	Lost Dauphin-Red Maple 138 (flo) Kewaunee-East Krok 138	WPS	Rel(OTDF),LODF
3627	Depere - Glory Rd 138 (flo) Kewaunee-E.Krok 138	WPS	Rel(OTDF),LODF
3701	Poweshiek-Reasnor 161 kV	ALTW	Rel
3702	Poweshiek-Reasnor for Arnold-Hazleton	ALTW	Rel(OTDF)
3703	Poweshiek-Reasnor161 for Arnold-Tifften	ALTW	Rel(OTDF)
3704	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	ALTW	Rel(OTDF)
3705	Arnold-Hazelton 345 for Wemp-Paddock 345	ALTW	Rel(OTDF),LODF
3706	Arnold - Hazleton	ALTW	Rel
3707	LOR5-TRK RIV5 161KV/WEMPL-PADDOCK 345KV	ALTW	Rel(OTDF)
3708	Adams 345/161kV TR9	ALTW,NSP	Rel,Com
3710	Adams 345-161 for Adams-Hazleton 345	ALTW	Rel(OTDF)
3711	Albany 161-138 for Nelson-Cordo B 345	ALTW	Rel(OTDF)
3712	Dundee 161-115 for Arnold-Hazleton 345kV	ALTW	Rel(OTDF)
3713	Lakefield 345-161 for Byron-Adams 345	ALTW	Rel(OTDF)
3714	Lakefield Jct.-Fox Lk 161 for Arnold-Hazelton 345	ALTW	Rel(OTDF)
3715	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	ALTW,CE	Rel
3716	Rock Creek 345/161 TR for Quad-Sub 91 345	ALTW	Rel(OTDF)
3717	Rock Creek-Dewitt 161 Quad Cities-Sub91 345	ALTW	Rel(OTDF)
3718	RockCreek-Dewitt 161 for meccord3-sub39 345kV	ALTW	Rel(OTDF)
3719	Salem 345/138 Quad Cities-Sub 39	ALTW	Rel(OTDF)
3720	Salem 345-138 TR for MEC Cordova-Sub 39 345kV	ALTW	Rel(OTDF)
3721	Salem 345/161 for Quad-Sub 91 TR	ALTW	Rel(OTDF)
3723	Tiffton-D.Arnold 345 for Montezuma-Hills 345kV	ALTW	Rel(OTDF),LODF
3724	Arnold-Vinton 161 for D.Arnold-Hazelton 345	ALTW	Rel(OTDF),LODF
3725	Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345	ALTW	Rel(OTDF)
3726	Ames-BooneJct 115 for Montezuma-Bondurant 345	ALTW	Rel(OTDF)
3727	Lakefield-Fox Lk 161 for Lakefield-LGS 345	ALTW	Rel(OTDF),LODF
3728	Dysart-Washburn 161 for D.Arnold-Hazelton 345	ALTW	Rel(OTDF),LODF
3729	Bondurant-BooneJct 161 for Sycamr-Lehigh 345	ALTW	Rel(OTDF)
3730	Bondurant-BooneJct 161 for Lehigh-Webster 345	ALTW	Rel(OTDF)
3731	Lakefield Jct.-Fox Lake 161 flo Lakefield Jct.-Triboji 161	ALTW	Rel(OTDF),LODF

NERC FG #	FG Description	CA Owners	FG Type
3732	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500	ALTW	Rel(OTDF),LODF
3733	Hazelton-Dundee 161 Arpin-Eau Claire 345	ALTW	Rel(OTDF),LODF
3734	E.Calamus-Calamus 115 for Arnold-Tiffin 345	ALTW	Rel(OTDF),LODF
3735	Wisdom-Triboji 161 flo Raun-Lakefield 345	ALTW,WAUE	Rel(OTDF),LODF
3736	Salem 345/161 flo Wempletown-Paddock 345	ALTW	Rel(OTDF),LODF
3737	Hills 345/161 Xfmr (flo) Tiffin-Duane Arnold 345	ALTW	Rel(OTDF),LODF
3738	8th St-Lore 161 flo Wempletown-Paddock 345	ALTW	Rel(OTDF),LODF
3739	8th St. - Lore 161 (flo) Arnold - Hazleton 345	ALTW	Rel(OTDF),LODF
5014	ElkXfrTucOku	CSWS	Rel(OTDF)
5017	FTSXFR500345	OKGE	Rel(OTDF)
5021	KilCreWooWic	OKGE,WR	Rel(OTDF)
5022	LacNeoLanWic	KCPL,WR	Rel(OTDF)
5023	LacStiLacWgr	KCPL	Rel(OTDF)
5035	MontroClintn	KCPL,AECI	Rel
5036	MuskogPittsb	OKGE,CSWS	Rel
5037	MusClaMusRss	OKGE,CSWS	Rel(OTDF)
5045	PhiSphSumEmc	WR	Rel(OTDF)
5050	StjLakIatStr	MPS,KCPL	Rel(OTDF),LODF
5051	StockMorgan	SPA,AECI	Rel
5052	StoMorLacNeo	SPA,AECI	Rel(OTDF)
5053	StoMorMorBrk	SPA,AECI	Rel(OTDF)
5063	NesOneNesTul	CSWS	Rel(OTDF)
5076	FtSmthANOVlt	OKGE	Rel
5077	CreKilWicWoo	OKGE,WR	Rel(OTDF),LODF
5081	OsaCanBusDea	SPS	Rel(OTDF),Cont,LODF
5083	HarNicHarNic	SPS	Rel(OTDF),LODF
5084	SwsFtcOkuTuc	CSWS	Rel(OTDF), LODF
5095	MadRamMckFrk	CLEC,EES	Rel(OTDF)
5099	PitSemPitSun	CSWS,OKGE	Rel(OTDF)
5100	PriSpePriSpe	SPS	Rel(OTDF)
5102	StrJarStrHoy	WR	Rel(OTDF)
5103	TucXfrTucCar	SPS	Rel(OTDF)
5194	FTSXFR345161	OKGE	Rel(OTDF)
5196	SPS North - South	SPS	Rel
5200	LacWgrLacSti	KCPL	Rel(OTDF)
6001	NDEX	WAUE,OTP,NSP,MP	Rel,Com
6002	MHEX_S	MHEB,WAUE,NSP	Rel,Com
6003	MHEX_N	WAUE,MHEB,NSP	Rel,Com
6004	MWSI	ALTE,WEC,WPS,NSP	Rel,Com
6006	GGS	NPPD	Rel,Com
6007	GENTLMN3 345 REDWILO3 345 1	NPPD	Rel,Com

NERC FG #	FG Description	CA Owners	FG Type
6008	GRIS_LNC	NPPD	Rel,Com
6009	COOPER_S	NPPD,MPS,AECI,OPPD	Rel,Com
6012	PRI-BYN	NSP,SMP	Rel,Com
6013	LKM-WFB	NSP	Rel,Com
6014	FTCAL_S	OPPD	Rel,Com
6015	ROCHSTR-ALMA / KING-ECL	DPC,NSP	Rel,Com
6017	LAKEFIELD XFMR / BYRON-ADAMS	SMP,ALTW	Rel,Com
6018	CENTER - HESKETT 230	OTP,WAUE	Rel,Com
6019	CENTER - JAMESTOWN 345	OTP	Rel,Com
6021	ENDERS-BEVERLY / GENTL-REDWIL	NPPD	Rel,Com
6022	GRISLD-YORK / GRISLD-MCCOOL	NPPD	Rel,Com
6023	N.PLATTE-STVL /GENTL-REDWIL	NPPD	Rel,Com
6024	RED WILLOW - MINGO	NPPD	Rel,Com
6026	JMSTN-FARGO 1 AND JMSTN-FARGO 2	WAUE	Rel,Com
6029	ROCHESTER-SILVER LAKE/PRI-BYRON	NSP,SMP	Rel,Com
6030	Nebraska City-Cooper 345kV	NPPD,OPPD	Rel,Com
6049	TEST-NPPD-OTDF WNE/WKS -13	NPPD	Rel(OTDF)
6051	TEST-NPPD-OTDF-WNE/WKS -15	NPPD	Rel(OTDF)
6056	JMS-PIC JMS-FARGO 1&2 FLO CEN-JMS]	OTP,WAUE	Rel,Com
6057	Sub T-Hills 345kV FLO Sub 93-Sub 92 345kV	MEC	Rel,Com
6059	Silver Lake-Rochester 161kV FLO Byron-Pleasant Valley 345kV	NSP,SMP	Rel,Com
6060	D602F 500KV	MHEB,NSP	Rel,Com
6061	R50M 230KV	MHEB,NSP	Rel,Com
6062	Cascade Creek - Crosstown 161 (flo) King - Eau Claire	SMP,NSP	Rel,Com
6069	Wabaco - Alma 161KV (flo) Eau Claire - Arpin 345KV	DPC,NSP	Rel,Com
6072	L20D 230kV	MHEB	Rel,Com
6073	Morningside-Plymouth 161kV FLO Raun-Sioux City 345kV	MEC,WAUE	Rel,Com
6074	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV	MEC	Rel,Com
6081	Quad City West 345kV	MEC	Rel,Com
6082	SUB 92-HILLS FOR LOSS OF LOUISA_SUB T	MEC	Rel,Com
6083	Cascade Creek-Crosstown 161kV FLO Byron - Pleasant Valley 345kV	NSP,SMP	Rel,Com
6084	East Moline 345/161 XFMER (flo) Quad Citites - Sub 91	MEC	Rel,Com
6085	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV	DPC	Rel
6086	Montezuma-Bondurant 345kV	MEC	Rel,Com
6087	Cascade Creek-Crosstown 161kV flo Adams Tramsformer 345/161kV	NSP,SMP	Rel,Cont
6088	Genoa-Seneca (flo) Eau Claire-Arpin	DPC,NSP	Rel,Com
6089	Cascade Creek - IBM FLO Byron - Adams	NSP,SMP	Rel,Com
6100	MHEB - SPC	MHEB,SPC	Rel
6101	MP_EXPORT	GREC,MP	Rel,Com
6102	St. Joe - Midway 161kV	MPS	Rel

NERC FG #	FG Description	CA Owners	FG Type
6104	Iatan - St. Joe 345kV	MPS	Rel
6105	Quad Cities - Rock Creek	ALTW,CE	Rel
6108	TURKEY RVR-CASSVILLE FLO WEMP-PADDOCK	ALTW, DPC	Rel(OTDF)
6110	McHenry-Ramsey 230 FLO Center-Jamestown 345kV	GREN	Rel(OTDF)
6111	GRAND ISLAND XFMR FLO GRAND ISLAND-MCCOOL	NPPD,WAUE	Rel(OTDF),LODF
6112	Byron-Maple Leaf 161 flo Byron-Pleasant Valley 345	SMP	Rel(OTDF),Cont
6113	Byron-Maple Leaf 161 flo Pleasant Valley-Adams 345	SMP	Rel(OTDF),Cont
6114	Wabaco-Alma 161 flo Prairie Island-Byron 345	DPC	Rel(OTDF),Cont
6115	St. Joe-Midway 161kV flo St. Joe-Fairport 345kV	MPS	Rel(OTDF),Cont
6116	Alma-Elk Mound 161 kV flo King-Eau Claire 345kV	DPC	Rel(OTDF),Cont
6117	Sub 92-Hills flo Sub 93-Sub T-Hills	MEC	Rel(OTDF)
6118	Sub 93-Sub 31T flo Quad-Rock Ck 345	MEC	Rel(OTDF)
6119	Adams 345/161 Xfmr flo King-Eau Claire Arpin 345	NSP	Rel(OTDF)
6120	Glenboro - Rugby 230 kV	MHEB,WAUE	Rel,Com
6122	Council Bluffs-Avoca 161kV flo Council Bluffs-Madison County 345kV	MEC	Rel(OTDF),Cont
6123	Raun-Sioux City 345kV flo Raun-Lakefield 345kV	MEC	Rel(OTDF),Cont
6123	Raun-Sioux City 345kV flo Raun-Lakefield 345kV	MEC	Rel(OTDF),Cont
6124	Sub K/Tiffin-Arnold 345kV	MEC	Rel
6124	Sub K/Tiffin-Arnold 345kV	MEC	Rel
6126	S1226-Tekamah 161kV flo S3451-Raun 345kV	MEC, OPPD	Rel(OTDF),Com
6127	Sub 1214-70th & Bluff 161kV flo Cooper-Nebraska City 345kV	LES,OPPD	Rel(OTDF),Com,Cont
6128	Morningside-Plymouth 161kV flo Raun-Sioux City 345kV	MEC, WAUE	Rel(OTDF),Com,Cont
7001	FRONTIER - GENESSEE	NYIS	Rel,Le
7002	GENESSEE - CENTRAL	NYIS	Rel,Le
7004	CENTRAL - CAPITAL	NYIS	Rel,Le
7009	IMO - FRONTIER	NYIS,IMO	Rel,MRD,Le
7101	BLIP-(Buchanan Longwood Input)	IMO	Rel,MRD,Le
7102	QFW-(Queenston Flow West)	IMO	Rel,MRD,Le
7103	EW-TR-E (East-West Transfer East)	IMO	Rel,Le
7104	NEGATIVE_BLIP(Negative Buch Lgwd Input)	IMO	Rel,Le
7106	FRONTIER - IMO	IMO,NYIS	Rel,Le
9084	MECS-IMO	MECS,IMO	Rel,Le
9092	PJM-NYIS	PJM,NYIS	Rel,Le
9156	NYIS-IMO	NYIS,IMO	Rel,Le
9159	IMO-MECS	IMO,MECS	Rel,MRD,Le
9160	IMO-NYIS	IMO,NYIS	Rel,MRD,Le
9161	IMO-MP	IMO,MP	Com,Le
9169	WSC3-NPPD	WSC3,NPPD	Com

Appendix G- Issues and Resolutions

The table on the following pages contains a comprehensive list of issues and questions that were identified from the following sources:

- MISO/PJM/SPP website comments
- MISO/PJM Seams Stakeholders meetings
- NERC OC Meetings
- NERC MISO/PJM Review Team Meetings
- Regional Meetings

The table attempts to list each issue that has been raised, and direct the reader to the documentation where the issue is addressed – or explain why it was not.

ISSUE	DOCUMENTATION/COMMENTS
1. Parallel Flows	
1.1. Congestion Management Procedures	
1.1.1. Why are market flows being split into only priorities 6 and 7 of the NERC curtailment priorities.	-All market flows within PJM and MISO would be are under their single, respective tariffs – and therefore candidates for Priority 6, network service or Priority 7, Firm. However, the proposal was enhanced to Prioritize flows committed same day to be Priority 2, non-firm hourly for those flowgates where owners agreed to a reciprocal coordination agreement.
1.1.2. Define steps that will be taken (redispatch first, TLR non-firm second, TLR firm third etcetera) for PJM, MISO, and 3rd party flowgates.	-This is covered in new section "Process to Respect Flowgate Capabilities"
1.1.3. Tagging in, out, or across markets – are MW impacts properly accounted for?	Interchange transactions are tagged back to marginal units per proposal to provide better granularity than today.
1.1.4. Do market flows include transactions in, out, or across market or only all control zones NNL plus inter control zone flows?	- Market Flows include all flows caused by generators in the market that are not tagged and provided to NERC IDC. Grand-fathered internal transactions are tagged and interchange transactions in, out or across the market will be tagged.
1.1.5. IDC modeling vs LMP modeling of flowgate impacts	- This proposal provides the mechanism to quantify, prioritize, and marry LMP market impacts on flowgates to the Tariff priorities in the IDC. The real-time modeling provided by the LMP systems will greatly enhance overall granularity of the IDC.
1.1.6. Creation of flowgates on the fly.	-"Process to Develop Flowgates on the Fly" is provided in this document.
1.1.7. Communications of curtailments back to RCs	-Communication of curtailments through same channels as used today – NERC IDC.

ISSUE	DOCUMENTATION/COMMENTS
1.1.8. Are generators that are within PJM but not part of the market included in calculating the "market flows"?	- Yes, all flows caused by generators in the market will be included in the market flow calculation. The market flow calculation is adjusted for tagged flows so double counting doesn't occur.
1.1.9. Multiple relief requests, how calculated?	- Once it is determined relief is needed on a flowgate and that TLR will be used, the Multiple relief requests will be handled sequentially as it is today in the IDC.
1.1.10. Explain calculation of market flows	-"Defining Monitored Flows" this document
1.1.11. Market Flow Calculation engine:	-RTO State Estimator/LMP engine will be used for accuracy.
1.1.11.1. LMP (pros/cons?)	- Robust, real time, and well maintained model that is also used to set LMP prices. Granularity down to the real time output of generators and actual load will provide greater accuracy. RTOs need ability to quantify flows/impacts outside IDC to enable RTO to RTO, Market to Market congestion management outside IDC to achieve greater efficiencies without calling TLRs.
1.1.11.2. NERC IDC (pros/cons?)	- Less accurate without major enhancements. Duplicative with RTO requirements for models needed to run markets.
1.1.11.3. Industry oversight of calculations – IDCWG or DFWG? Auditable, repeatable, verifiable calculations?	- RTOs will provide mechanism for NERC to audit calculations. See Appendix K.
1.1.11.4. Synchronicity of models	- Achieved through use of real time ICCP/ISN data for observable areas of market and with SDX data for outlying areas.
1.1.12. Why isn't the real-time shift of generation under market operations (or more specifically the difference between the day-ahead market dispatch and the real-time dispatch) not being treated similar to non-firm redirects in the hourly market.	- Will be considered non-firm hourly priority with parties willing to reciprocate actions
1.1.13. NNL Calculation:	-"Calculation of NNL" this document
1.1.13.1. Real time – for real time, will PJM be getting 5 second scans? Every 6 minutes? What is the scan-rate?	- Will provide market flows to IDC at least every 15 minutes (as requested by OATI and the IDCWG, the RTOs could provide updates as often as every 5 minutes..
1.1.13.2. Will the market flow methodology be used to determine the market flow impact on all flowgates? Will MISO use the same methodology once their market is up? If not, what is the guarantee that comparability will be achieved?	- Will be used for all Coordinated Flowgates as defined in paper. MISO and PJM will use same methods when MISO's market starts and PJM expands.

ISSUE	DOCUMENTATION/COMMENTS
1.1.13.3. In your (PJM's) realtime model, you are going to run sensitivity studies. How far do your model(s) go out? Are they robust enough to capture flows/impacts in Michigan? Wisconsin? Missouri?	- In order to model the Coordinated Flowgates, PJM EMS model will grow from a 7,000 bus model to a 24,000 bus model. As such, PJM is very confident that its model will be more than robust enough to capture all of its flows on each of the Coordinated Flowgates it impacts.
1.1.13.4. Display "timeline" of this process.	- See examples.
1.1.13.5. How to calculate NNL service for new network resources (e.g., generators)	- MISO and PJM will use existing processes to designate new network resources.
1.1.14. Tagging Issues and Solutions:	
1.1.14.1. Would the IDC ignore those transactions/tags in, out, and through PJM regarding the market coordination flowgates as they relate to calculating distribution factors and/or impacts in lieu of the values submitted by PJM	-All tag impacts will be calculated/ represented by the IDC just as they are today – regardless of whether viewing a coordination flowgate or other flowgate. MISO and PJM will, however, provide better information to IDC as to the source or sink of those transactions.
1.1.14.2. If using the marginal generator to calculate the distribution factors, how would the IDC be aware of the marginal generator?	-Marginal units within PJM and MISO will be communicated to IDC in the form of generation participation factors
1.1.14.3. Why would it be advantageous for the RTO to calculate TDFs vs the IDC?	- This concept was is earlier draft proposal and is no longer being pursued Additionally, both the NERC MISO/PJM Review Team and NERC OC endorsed the concept of the RTOs making these calculations.
1.1.14.4. How determined what of Market Flow impacts will be considered 6NN and what will be considered 7-F	See Sections 5 and 6.
1.1.14.5. How to avoid double-counting Firm pt-pt schedules	- Process provides method so "partial path reservations" are not double counted.
1.1.14.6. How will you synchronize timing of MISO and PJM flow calculations (every five minutes) with the IDC calculations?	- Calculations will be performed at least every 15 minutes at an agreed upon time.
1.2. ATC/AFC Coordination	

ISSUE	DOCUMENTATION/COMMENTS
1.2.1. AFC calculation and consideration of external flowgates	- MISO and PJM are offering to coordinate AFC/ATC calculations with any external parties wishing to do so. As per the Appendix on MISO/PJM AFC Coordination, the RTOs will each be respecting over 300 flowgates external to their respective boundaries.
1.2.2. If your firm AFC calculations are based on day-ahead, how firm is day-ahead? If it is not extremely accurate, PJM's firm allocation could be taking up room on a flowgate, while in reality the total MWs flowing current day may only be a fraction of the allocation that was calculated day-ahead. This could result in keeping people off of flowgates when there is in fact room on the flowgate. And currently this could be done for free, because the PJM customer would not have to pay for it unless they used it.	AFC and NNL calculations will allocate firm room on flowgates in advance to those parties participating in the reciprocal agreements to coordination firm/NNL on those flowgates. Any unused flowgate capabilities are released for non-firm near real time.
1.2.3. If there is any capacity left after MISO and PJM have made a determination, what is timeframe for making use of this capacity?	- Non-firm, Priority 6 is made available on a day-head basis and non-firm hourly is made for current day.
1.2.4. Define transmission allocation/ entitlement	- Process to account for firm and no-firm commitments on flowgates to help present over subscription of capabilities.
1.2.5. Need to make sure service is granted on the same basis it's being curtailed.	- Service will be curtailed under the same priority as was granted. Location of source and sink generators are estimated when service is granted. Process provides for mapping service back to zones where generation will be adjusted should service be curtailed.
1.2.6. When the market expands, will the market gain firm rights outside the market that they do not own currently? Why should a control area gain firm rights that they did not have before – simply because the market expands?	- No, default will be level of firm that they would have had if the market did not expand. If additional firm room is available, Reciprocal Entities that agree to do so will allocate reaming room to prevent over subscription. Additionally, the calculation of NNL permits the RTOs to enhance granularity of determining all of the economic impacts on external flowgates so that the RTOs can aggressively respond to a TLR.
1.2.7. Are you considering every generator a separate designated resource for all PJM load?	- No, designated resources are designated to their customer load. For example, designated resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
1.2.8. Define "Historic NNL"	- Process to quantify the firm capabilities, for both network service and point-to-point inside the market, control area by control area that entities would have had if markets did not start or expand. "Historic" refers to historic or present process to quantify those values but does not refer to the level of firm for some past period.
1.2.9. How would you consider external transactions?	- They will be tagged and consider same as today. However, this proposal provides far more granularity to where actual generators will be moving to support schedule changes (this granularity will be in the form of the list of real-time marginal units).
1.2.10. Is there any coordination on non-firm?	See Sections 5 and 6

ISSUE	DOCUMENTATION/COMMENTS
1.2.11. Loop flows are still not being accounted for. Therefore, if you calculate the ATC/AFC without accounting for loop flows, won't you oversell the flowgate?	- Loop flows are estimated and accounted for in processed to help minimizing overselling of the flowgates.
1.2.12. Need to work out a means for 6NN within PJM to be considered 6NN within MISO, and visa versa.	- Per suggestion of Stakeholders, process is provided to account for Priority 6-NN among all Reciprocal Entities.
1.2.13. In the day-ahead commitment, you (Tom Bowe) said that you will respect the NNL limits as related to the list of flowgates that you agree on. Won't this falsely limit PJM?	The final draft of the Whitepaper, provides clarification to this question. The RTOs will not bind the Coordinated Flowgates to the NNL value unless the outage coordination and recent TLR activity show the need to limit the flowgate in the day ahead commitment. The RTOs will further restrict their reciprocal flowgates to respect one another's anticipated dispatches and schedules.
1.2.14. Once an "allocation of usage" of a flowgate is determined by MISO and PJM, when additional parties come into the mix in the future (Duke), won't the allocations have to be re-negotiated/re-calculated?	- Allocations may be recalculated if additional parties wish to join reciprocal process. Same process will be utilized to determine new parties' base usage and "Historic NNL".
1.2.15. If someone wants to purchase transmission for this summer, how will this be handled both before transition and after? How will existing purchased transmission be handled during the "transition"?	For this summer, same as today. Transmission service within a market will be converted and utilized according to that market's rules.
1.2.16. Complete and post the ATC/AFC Coordination agreement.	- ATC/AFC Coordination Agreement is an appendix of this paper.
1.2.17. Explain process of AFC Coordination with third/outside parties?	- Any party that wishes to participate can.
1.2.18. Explain ATC coordination across the EI.	- Only those that agree to will participate in the MISO/PJM ATC. AFC Coordination. Outside of that, different processes are used.
1.2.19. Explain conversion of grandfathered firm pt-pt	- grand father firm pt-to-pt will be converted per market rules where they apply or may remain same service and be tagged as today.
2. Contract Tie Capacity	
2.1. One Stop Shopping	- Out of scope of this process
3. Different Definitions/Procedures between RTOs	
3.1. Emergency & Restoration Procedures	Emergency & Restoration Drills held 11/02
3.2. Operating Procedures for Voltage Collapse & Stability	-Included in Attachment A of MISO & PJM Reliability Plans
4. NERC Regional Criteria and Reserve Sharing	
4.1. Define NERC Operating Policy changes, waivers, or certifications that are needed to permit security-constrained dispatch over multiple existing Control Areas and to allow	Wavers are requested from NERC for Policy 3 and Policy 9. Policy 3 – Waiver request permission for PJM and MISO to provide market flow impacts to IDC instead of providing information by E-

ISSUE	DOCUMENTATION/COMMENTS
flows to not be tagged between Control Zones. Potential Policy 1, Policy 3, and Policy 9 changes may be required.	Tags. Policy 9 –Waiver requested to permit prioritization and reduction of market flow impacts on same basis as tagged interchange transactions. Waiver also requests that market flows be calculated actual flows rather than only using positive flows of 5% impact or greater. Security Coordination.
4.2. How does a market entity (PJM or MISO) respond to Reserve Sharing events?	Methods will be similar as today and will be defined within each market's rules. Reserve Sharing is beyond the scope of this proposal to manage congestion.
4.2.1. Events with ECAR, only (former) ECAR CA's respond?	- This proposal respects and does not change reserve sharing pools and arrangements.
4.2.1.1. Studies and transmission margin already in place to handle the transfer of energy across network to needing party	- MISO and PJM have agreed to coordinate TRM/CBM to allow reserves to flow when called upon.
4.2.2. Events within ECAR, all of the market entity (PJM or MISO) generation resources respond?	- This proposal respects and does not change reserve sharing pools and arrangements.
4.2.2.1. This could impact transmission facilities where a transmission margin and associated studies are non-existent and cause overloads or other problems not previously anticipated	- Existing reserve sharing groups are not changed by this proposal.
5. Facilities in Close Electrical Proximity under Different RTOs	
5.1. Outage Maintenance Coordination	- Procedure included as appendix of this document.
5.2. Access & Expansion Planning	- MISO and PJM have agreed to coordinate Access & Expansion Planning. Procedure will be documented by separate agreement.
6. Market flow calculation, reflect ISN and SDX data	- Yes, State Estimator results that are used to calculate market flows utilize ISN and SDX data. State Estimators use of real time ICCP/ISN data for observable areas of market and SDX data for outlying areas.
7. Control Area/Control Zone responsibilities?	-Control Area responsibilities haven't changed. However, market operator may perform some of the responsibilities. - Control Zones recognize former Control Area boundaries where the market operator performs many of the traditional Control Area responsibilities. Control Zone boundaries are utilized when calculating historic NNL in PJM.
8. GLDF calculation. GLDFs depend on where the load is located. What is the % threshold?	- For Market flow calculation, the load is the entire market. For Historic NNL calculation, the load is the former Control Area. Percent threshold is 0% in order to calculate actual impacts and not only positive impacts of 5% or more.

ISSUE	DOCUMENTATION/COMMENTS
9. Regarding wide area dispatch and network resources to network loads, Not all loads in PJM are firm network loads. Resource deliverability?	True. Designated resources are designated to their customer load. For example, designated resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
10. Will you keep former CAs in the model?	Yes. Only for the purposes of calculating historic NNL, and calculating projected flows between what was once the CA's so that RC's do not lose the information they need to conduct their day-ahead studies.
11. Define coordination that will take place between the market entity (PJM or MISO) and the IDC	- MISO and PJM will input market impacts to IDC and will follow curtailment orders received by IDC.
11.1. Define necessary IDC changes	- IDC will be changed to allow market flows to be prioritized and uploaded to IDC and curtailed/redispatch on same basis as interchange transactions R-tagged and entered into IDC. MISO and PJM will also provide more granular information to IDC regarding to sources and sinks of interchange transactions flowing in or out of the markets. IDC changes are documented in NERC Change Order 114.
11.2. Will coordination include updates of network model base cases and the Book of Flowgates?	Yes.
12. Industry oversight of PJM impact calculations.	- MISO and PJM will provide audit process to NERC. See Appendix K.
12.1. IDC cost issue	- MISO and PJM will pay for changes needed to implement this proposal in IDC.
12.2. Cost allocation.	- MISO and PJM split 50/50 NERC costs for changes needed to implement this proposal in IDC.
13. Contingency plans? Critical path analysis.	RTOs committed to reliability. Implementation will be delayed until ready. Approval of plans, completion of IDC changes, testing/training or processes in IDC training server.
14. Selection process of market/TLR Coordinated Flowgates	-Process/Criteria to Determine Flowgates in this document
14.1. FTR and ARR auction in PJM April, are these shared flowgates going to be included in the auction	-Yes, immediately prior to market implementation
14.2. How is it determined those flowgates the market has an effective control of	- Criteria to determine Coordinated Flowgates is used to identify flowgates ahead of time that market will have effective control of its flow over. See Section XX
14.3. What if there are flowgates that see a significant flow from the market but the market doesn't have an effective control	- Criteria should screen those out. However, market can pay market/entities outside it market to provide redispatch. MISO will pursue agreements with neighboring entities
14.4. Need to ensure criteria for selecting flowgates includes all flowgates actually and significantly impacted by market flows.	Agreed, goal of criteria is to identify and include such flowgates. PJM has sent the list of 240+ Coordinated Flowgates to all interested parties. In the two+ months parties have had to review the process only two entities has provided feedback (for a total of 4 additional flowgates)
14.5. 5% threshold doesn't correct parallel flow problem. Need MW % usage.	- Criteria allows for inclusion of significantly utilized flowgates with less that 5% impact on a case-by-case basis.
14.6. On the 5% limit, in the study you are referring to, because of the magnitude of the market flow, even 3% of a large amount of	Need to use a method to screen flowgates so that flowgates where market doesn't have effective control over are not included. For example, Market can't redispatch 1000 MW to remove 1 MW of flow.

ISSUE	DOCUMENTATION/COMMENTS
energy could easily overwhelm a flowgate. Why use the 5% threshold – just when coming up with the list of market coordination flowgates?	5% threshold is needed to develop list of flowgates because market impacts will be calculated down to 0% on those flowgates. If 5% screen is not used, flowgates may be included where market have very ineffective control.
14.7. Develop process where significantly impacted (ex. 20% of Market Flow) flowgates may be added to list.	- Criteria allows for inclusion of significantly utilized flowgates with less that 5% impact on a case-by-case basis.
14.8. Need to address how we phase in list of flowgates based on Market Growth Timeline	Studies will be performed based on areas included in the market for each time frame. The List of Flowgates Appendix shows how the initial studies have shown how this list will incrementally grow to support the Market Growth timeline.
14.9. If there is disagreement, who will make the final determination of whether a particular flowgate is or is not included?	- NERC Operating Reliability Subcommittee or NERC Operating Committee.
14.10. Why not perform a study on all flowgates in the BOF – but not add them unless they are needed. Then the calculation would already have been completed.	- All Flowgates in NERC Book of Flowgates will be included in initial screening. Criteria for determining flowgates are exhaustive. Need to have process to add flowgates on the fly if new flowgate, not already in the IDC, is needed.
14.11. Why is it so important to come up with a relatively finite list of flowgates right now. Then attempt to add flowgates in the future “on the fly”.	Threshold is applied when defining list of flowgates since market flow is calculated down to 0%. - Always need to be able to add flowgates on the fly if new constraint, not in the IDC, is identified.
14.12. Why not just have the market entity send information to the IDC and let it calculate the market impact?	- More accurate and efficient for market entity to calculate flows. Will enable market to market coordination outside of IDC and TLR.
14.13. “We (PJM) will allow MISO to audit us and determine if our redispatch and calculations are accurate and effective.”	- MISO will also allow PJM to audit calculations.
14.14. Will all studies and their results be made posted or made public?	- As appropriate respecting confidentiality requirements.
14.15. Are MISO and PJM only considering flowgates for the list that are within MISO or PJM?	- The RTOs have determined many 3rd party flowgates per criteria.
15. What happens when MISO Firm and NNL + PJM Firm + NNL + 3rd parties firm and NNL + TRM and CBM > TTC?	
15.1. How will day-ahead processes reduce planned flows when oversubscribed?	- No mechanism to ratchet down oversubscribed flows day ahead. Many flowgate may already be over subscribed, by the current transmission providers. Will conduct Next –Day Reliability Analysis to ensure reliable system next day and identify required actions. Will use real time processes to reduce flows as needed. Additional MISO/PJM AFC coordination may avoid oversubscription of some flowgates.
16. Sunset Provision	

ISSUE	DOCUMENTATION/COMMENTS
16.1. Why not implement a sunset date for these procedures of December 1, 2003 – or such time as MISO implements its Day 2 market.	- MISO will utilize these procedures to enable its market to start. Will build upon, enhance, and adjust these procedures as needed with proper approvals.
17. Seams Agreement needs to be completed	- MISO and PJM plan to have a Coordination Agreement, which will include seams agreements.
18. Interaction with ATCo's Attachment K	
18.1. Possible joint redispatch agreement between ATC (and the generators on ATC's system) and PJM?	-May be handled in market-to-market environment. Should PJM's market expansion be delayed, MISO will pursue agreements with neighboring generators to achieve more economical redispatch results.
19. Define "RTO Area Wide Dispatch"	- Market area wide central, security constrained dispatch of generation in market.
20. Parallel Flows are not being paid for	-Clearly a compensation issue that needs to go to FERC.
21. Historic NNL values should not be reflected indefinitely in the future, and an appropriate mechanism to rationalize the historic flows to recognize eventual market conditions should be developed	- Absolutely. A new mechanism will need to be designed.
22. Which of these processes will change or go away once MISO and PJM are both operating their full markets? Which ones will remain in place?	- These procedures will remain in place, be built upon, and enhance for the Market-to-Market Coordination.

Appendix H- Training

The concepts in these proposals should not have a significant impact upon System Operators beyond the Operators of the RTOs. The reason that this impact rests upon the RTOs is that the RTO Operators will need to be trained to monitor and respond to the external flowgates.

RTO Operator Training Impacts include

1. The ability to recognize and respond to Coordinated Flowgates.
    a. IDC outputs will show schedule curtailments and possible redispatch requirements.
    b. Must be able to enter constraint in systems to provide the redispatch relief within 15 minutes
    c. Must be able to confirm that the required redispatch relief has been provided and data provided to the IDC.
2. Capability to enter flowgates on the fly.

Other Reliability Coordinator (RC) System Operators Training Impacts include:

1. The ability to take projected net system flows between an RTOs control zones versus only tag data to run day-ahead analysis (data to be provided by the IDC).
2. Need to develop a working knowledge of how relief on a TLR flowgate can come from both schedule changes and redispatch on a select set of Coordinated Flowgates.
3. Can coordinate with an RTO Operator when the RC System Operator has a temporary flowgate that they believe requires the implementation of the "Flowgate on the Fly" process.

Appendix I- PJM/MISO Generation and Transmission Outage Coordination

PJM and MISO will jointly develop protocols for sharing transmission and generation outage schedule data. PJM and MISO agree to the following with respect to transmission and generation outage coordination:

Exchange of Transmission and Generation Outage Schedule Data

The projected status of generation and transmission availability will be communicated between the RTOs while respecting data confidentiality agreements. All available information regardless of scheduled date will be shared. PJM and MISO shall exchange the most current information on proposed outage information and provide a timely response on potential impacts of proposed outages.

PJM and MISO both have their own different outage scheduling applications. Ideally these applications should both be supplemented with a common process to automate the exchange of this information between the systems to minimize manual duplication of information and to assure that both RTOs have access to the same outage information.

Until this is accomplished, the RTO's will use email as the primary method to communicate new outage requests, and changes to outage requests, to the potentially impacted RTO that has indicated an interest in receiving the facility outage information. The potentially impacted RTO shall respond via email (and voice communication) and identify any proposed outage that is expected to impact the reliable economic operation within their RTO.

The RTO's agree that this information will be shared as soon as the information is available but at least daily and more often as required by system conditions. The RTOs shall jointly develop a common format for the exchange of this information. The information shall include (but not be limited to) owning RTO's facility name; proposed outage start date & time; proposed facility return date & time; date and time when a response is needed from the impacted RTO to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

Each RTO will also independently provide information on approved and anticipated outages formatted as required for the NERC SDX System.

Evaluation and Coordination of Transmission and Generation Outages

As described above, the RTOs will exchange transmission and generation outage data. Initially each owning RTO shall provide the other RTO a listing of facility names that they will use to identify the facilities in their footprint and the other RTO shall respond by identifying which facilities they are interested in receiving outage information about. Updated facility lists should be exchanged at least twice a year. The RTOs will also exchange lists of operations personnel involved in outage coordination and outage coordination procedures.

The RTOs will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each

RTO's outage analysis will consider the impact of its critical outages on the other RTO's system reliability, in addition to its own.

On a daily basis, the Operations Planning staff of each RTO shall jointly discuss outages for potential impacts. These discussions should include an indication of either concurrence with the outage or identify significant impact due to the outage as scheduled. Neither PJM nor MISO has the authority to cancel the other party's outage (except RTO to RTO tie lines). However, the RTOs will work together to resolve any identified outage conflicts. Consideration will be given to outage submittal times and outage criticality when addressing outage conflicts. If outage analysis indicates unacceptable system conditions, the RTOs will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of such proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the RTO's shall discuss the facts involved and make every effort to act on behalf of the other RTO to effect the requested schedule change. If this change cannot be accommodated, the RTO with the outage shall notify the impacted RTO. A request to adjust a proposed outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the outage to be successful.

The RTOs will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known. The RTO's will evaluate the impact of emergency and forced outages on the RTOs' systems and work with one another to develop remedial steps as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each RTO will consider the impact of these changes on the other RTO's system reliability, in addition to its own. The RTOs will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial steps as necessary.

Appendix J- PJM, MISO, and SPP ATC Coordination Document

Purpose and Background

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its ruling on the voluntary establishment of Regional Transmission Organizations (RTOs). This ruling, Order 2000, establishes a set of minimum characteristics and functions required of all RTOs. One of the functions required of RTOs by Order 2000 is Interregional Coordination. To fulfill this function, FERC requires that the RTO must ensure the integration of reliability practices within an Interconnection and market interface practices among regions. The integration of market interface practices among regions includes the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures. The RTO is required to develop mechanisms to coordinate their activities with other regions. While it is not required to include the mechanisms at the time of RTO application, reporting requirements must be proposed by the RTO to provide follow-up details for how the RTO is meeting the coordination requirements.

Representatives from the former Alliance companies, Midwest Independent System Operator (MISO), and Southwest Power Pool (SPP) have been involved in a collaborative process to detail the data exchange requirements and mechanisms, data usage principles, and coordination of methodologies necessary to calculate TTC and ATC values for a seamless market interface.. This document describes the agreements reached to facilitate fulfillment of this specific coordination requirement imposed by Order 2000 on all RTOs. Subsequent to this process, a number of the former Alliance companies decided to join PJM. Therefore, PJM has become a party to this procedure.

I. Data Exchange

The vast Eastern Interconnection is highly integrated and capable of reliably transmitting energy over long distances. The operational control of this Interconnection is distributed among various transmission providers and control area operators. The localization of control is accomplished effectively on a regional basis by RTOs, which provide the direct supervision necessary to respond to transmission contingencies and operational emergencies in a swift and effective manner. Typically, these contingencies will impact the operation in the vicinity of the contingency. For example, the status of the transmission system in New England has very little impact on the operation of the transmission systems in the Mid-Continent and Southern regions. However, one should not conclude that each of these transmission systems can or should operate independently. Since the Eastern Interconnection connects all transmission systems within the Interconnection, the conditions within one region can impact the loadings, voltages and stability of others within the Interconnection. The magnitude of this impact is a function of generation status (including the generation serving specific loads), transmission configuration, and load level. Since the operation of one system will impact the operation of neighboring systems, data must be exchanged in order to maintain the reliability of the Interconnection.

The calculation of Total Transfer Capability and Available Transfer Capability is a forecast of transmission capacity that may be available for use by transmission customers. Such use also impacts the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data in order for each entity to determine the TTC and ATC values for its own transmission system. This data is also necessary so that one RTO can refuse transmission service, if it is determined that the reservation request under consideration—if implemented—may overload facilities in the adjacent RTO.

The NERC SDX System currently is used to exchange statuses of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven days, weekly data for the next month and monthly data for the next year. Since this tool is currently being used and is maintained by NERC, the parties to this discussion believe that it would be prudent to use existing tools and methods as much as practical to accomplish the needed data tasks and avoid duplication of effort to the extent possible. Therefore the participating RTOs have agreed to fully populate the SDX System and update the data in the SDX System on a daily basis.

Therefore, the following data must be exchanged for each RTO to adequately determine its own TTC and ATC values and determine the impact of a proposed transmission service request on adjacent systems. Appendix A contains the procedural details of this data exchange.

Generation Outage Schedules from SDX

The projected status of generation availability over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that this data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete generation maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'return date' of a generator—either from a scheduled or forced outage—is necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the generator availability data provided to the other RTOs will be the most current data available. If the status of a particular generator of less than 150 MW is used within an RTO's TTC/ATC calculation, the status of this unit shall also be supplied via the NERC SDX System.

Generation Dispatch Order

In addition to the availability status of each 'significant' generator in a neighboring RTO, the dispatch of the available generation is necessary to accurately model future transmission system conditions. Broad assumptions can be made concerning generation, such as scaling all available generation to meet the generation commitments within an area and then increasing all generation uniformly to model an export, or similarly uniformly decreasing all generation to model an energy import. Excluding nuclear generation or hydro units from this scaling would provide some level of refinement. It was agreed that this simplistic approach may not be adequate to identify transmission constraints and determine rational TTC/ATC values. On the other extreme, economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment. It was recognized that this level of refinement was generally unnecessary, and the data will likely be considered confidential by the generation owners, and therefore unavailable. As a practical alternative, each RTO will provide each neighboring RTO a typical generation dispatch order or generation participation factors of all units on a control area basis. With this information, combined with the availability of the units as provided by the SDX System, a reasonably accurate dispatch can be developed as necessary for any modeled condition. The generation dispatch order would be updated as required by changes in unit statuses; however, it is envisioned that a new generation dispatch order would not be necessary more often than prior to each peak load season.

Transmission Outage Schedules from SDX

The projected status of transmission outage schedules over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that these data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete transmission facility maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'outage date' and 'return date' of a transmission facility (either from a scheduled or forced outage) are necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the available data provided to the other RTOs will be the most current data available. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC of an RTO, the status of this facility would also be supplied via the NERC SDX System.

Transmission Interchange Schedules and Reservations

Schedules

The existing transmission reservations and interchange schedules of each neighboring RTO are also required to accurately determine the TTC and ATC values. Since interchange schedules impact the short-term use of the transmission system, the interchange schedules are necessary to determine the remaining capacity of the transmission system as well as determine the net impact of others' activities on the operation of each RTO. The resultant 'loop flow' has a direct impact on the amount of transmission service that can be accommodated by a transmission system. The parties have agreed that the interchange schedules will be made available to neighboring RTOs for their use. Because of the shear volume of this data, it may be more practical to post these data to a FTP site for downloading by neighboring RTOs as required by their own process and schedules. As an alternative, the parties have considered requesting NERC to modify the IDC to allow for selected interrogation by the RTOs. The actual method used to accomplish this data exchange will be determined in future discussions.

Reservations

Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of TTC and ATC for future time periods. The actual transmission reservation information will be exchanged among the RTOs for integration into their own TTC/ATC determination process. This information will also be made available via an FTP site. However, since a transmission reservation is a 'right to use' not an obligation to use the transmission system, the certainty of any particular reservation resulting in a corresponding interchange schedule is open to some level of speculation. This is especially true considering that the pro forma tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, as yet, purchased all transmission reservations on a particular source-to-sink path. Further complicating this dilemma is that the duration or firmness of the 'second half' of the reservation may not be the same as the 'first half'. Therefore, since the portions of a source to sink reservation may not be able to be associated, prior to scheduling, double counting in the ATC determination process is a possibility. Therefore, information exchange regarding transmission reservations is necessary; however, the reservations themselves may not be incorporated into transmission models of the neighboring RTO. Each RTO will develop practices for modeling reservations, including external reservations, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. The procedures developed and implemented by each RTO to model intra-RTO reservations, reservations on external RTOs, and reservation netting practices will be shared with all adjoining RTOs.

Each RTO should also create and maintain a list of reservations from their OASIS that should not be considered in ATC calculations. Reasons for these exceptions may include grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-RTO partial path reservations. If the RTO does not include it in its own evaluation, it should be excluded in other RTOs' analysis.

Load Data

Peak load data for the period (e.g. daily, weekly and monthly) will continue to be provided via the NERC SDX System. Since, by definition, peak load values may only apply to one hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next 7-day horizon, it was agreed to either: supply hourly load forecasts OR daily peak load forecasts with a load profile. All load forecasts would be provided on a Control Area basis.

Calculated Firm and Non-firm Available Flowgate Capability (AFC)

The Available Flowgate Capability (AFC) is the applicable rating of the Flowgate less the projected loading across the particular flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, while the non-firm AFC is determined with both firm and non-firm reservations (or interchange schedules) modeled. Each RTO will accept or reject transmission service requests based upon projected loadings on their own flowgates as well as the loadings on ‘foreign’ flowgates, this data is required to determine if a transmission service reservation (or interchange schedule) will impact flowgates to an extent greater than the (firm or non-firm) AFC. Therefore, the Firm and Non-firm AFC for all relevant flowgates will be exchanged among the RTOs. Each RTO will also limit approvals of Transmission Service Requests so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the RTOs.

Available Flowgate Rating

The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the flowgate. The flowgate rating is in units of megawatts. If the flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions. The RTOs will provide the neighboring RTOs with (seasonal, normal and emergency) ratings as well as the limiting condition (thermal, voltage, or stability). This information will be updated as required by changes on the system, but these ratings are currently fairly static values and do not currently require frequent updating.

Identification of Flowgates

Flowgates that may initiate a TLR event must be considered in the RTO’s TTC and ATC determination process. Foreign Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating RTO’s model, as practical.

Configuration/facility changes (for EMS model updates)

Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The short term TTC/ATC determination processes are (will be) based upon an EMS model of the transmission system. Since frequently comparing the MMWG cases with the RTO's EMS models would be a significant, if not impractical task, a mechanism must be instituted to ensure that all significant system changes of a neighbor are incorporated in each RTO EMS model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the EMS based Models in a more timely manner. This type of data change would be similar to the 'New Facilities' Listings usually included in Interregional reports; however, explicit modeling information would need to be supplied along with the listing. It is envisioned that this data exchange should occur no less often than prior to each peak load season. In addition, the RTOs agree to exchange EMS models of their transmission systems as mechanisms can be established to facilitate this exchange.

Appendix K- Audit Procedures

MISO and PJM Market Flow, NNL, and Economic Dispatch Audit Procedure

MISO and PJM each under go rigorous internal and external audits of their processes (including SAS 70 Type II audits) to ensure they document processes, have proper control checks on their processes, and strictly follow the processes. Employees are required to follow the processes as a condition of employment at each organization. Further, MISO and PJM each are independent organizations and adhere to FERC's requirements for independence.

MISO and PJM will be calculating Market Flow, prioritizing those flows, and providing them to the IDC. The NERC IDC will calculate curtailment and redispatch requirements based, in part, on the MISO and PJM provided inputs. To provide even greater confidence that MISO and PJM are following the established processes for calculating these IDC inputs, MISO and PJM each volunteer to undergo this NERC administered audit process. The audit process will be pattern after the previous NERC Tag Audit. The audit process is as follows:

1. Once per month and after-the-fact, NERC will choose a time and Coordinated Flowgate to audit. The time chosen will typically be during an hour when TLR activity was occurring on one of the Coordinated Flowgates where MISO and/or PJM provide market flow values.

2. PJM and MISO will provide a record of loads, zonal generation, calculation, distribution factors, market flow calculations for the audit time, and resulting values provided to the IDC. Data confidentiality requirements of MISO, PJM, NERC, and FERC will be strictly followed.

3. NERC Staff will compare audit report results with values that were actually provided to the IDC for audited flowgate and report any discrepancies to the NERC Operating Reliability Subcommittee (ORS).

4. The ORS will monitor this audit process and make recommendations for improvements as necessary.

5. Once three successful monthly audits are completed, the audits will be conducted quarterly.