Index of Regional Differences in Reliability Standards

Version 0 – Draft 3 November 1, 2004

Updated December 20, 2004 (Changes highlighted)

Reliability Standard	Regional Difference	Region/Entity	Approval Date
BAL-001-0	Control Performance Standard 2	ERCOT	11/21/2002
BAL-006-0	RTO Inadvertent Interchange Accounting	MISO	3/25/04
INT-001-0 INT-004-0	Tagging Dynamic Schedules and Inadvertent Payback	WECC	11/21/2002
INT-002-0 INT-003-0	Scheduling Agent	MISO/SPP/Grid South	11/21/2002
INT-002-0 INT-003-0	Enhanced Scheduling Agent	MISO	7/16/2003
INT-001-0 INT-003-0	Energy Flow Information	MISO	7/16/2003
IRO-006-0	Enhanced Congestion Management (Curtailment/ Reload/Reallocation)	PJM/MISO	3/25/04

The following existing waivers no longer apply to NERC standards for the reasons noted:

Reliability Standard	Regional Difference	Region/Entity	Approval Date
NA	Financial Inadvertent Settlement: Inadvertent payback procedure and methods assigned to NAESB for development as Version 0 business practice standards.	MISO	11/21/2002
NA	Western Interconnection Thresholds to Initiate Manual Corrections for Time Error Time error correction procedure and methods assigned to NAESB for development as Version 0 business practice standards.	WECC	2/8/04

Effective until the Balance Resources and Demand Reliability Standard is approved, provided ERCOT remains a single Control Area Interconnection.

Waiver Request – Control Performance Standard 2

Organization

ERCOT

Operating Policy

ERCOT requests a waiver from Policy 1, "Generation Control and Performance," Section E, "Performance Standard" as follows:

Standards

1.2. **Control Performance Standard (CPS2)**. The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}.

Requirements

2. **Control Performance Standard (CPS) Compliance**. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).

Explanation

ERCOT requests a waiver from the CPS2 Standards and Requirements listed above for the following reasons:

1. On July 31, 2001, the ERCOT Interconnection began operating as a single CONTROL AREA, asynchronously connected via two DC ties to the Eastern Interconnection. At that time, ERCOT changed from the traditional tie-line bias generation control algorithms in which ten CONTROL AREAS participated, to a single 15-minute interval competitive balancing energy market and a frequency control system that regulates around the balancing energy schedule on two-to-four-second intervals. ERCOT requests that the Operating Committee reconsider CPS2 to ensure it is feasible under this new type of market-based control.

   If the Operating Committee believes that the CPS2 is feasible, then ERCOT would suggest that Policy 1 (or the appropriate Compliance document) provide for a "test period" of six months to allow CONTROL AREAS making such a transition the opportunity to test new control algorithms *provided* they can show that reliability is not degraded during that period. ERCOT also believes that its L_{10} may not be appropriate as it is less that half of the L_{10} of another NERC CONTROL AREA of similar load size.

2. The ERCOT Interconnection is now a single CONTROL AREA asynchronously connected to the Eastern Interconnection, and cannot create inadvertent power flows or frequency errors in other CONTROL AREAS. Therefore, the ISO questions whether the CPS2 Standard is necessary or even beneficial for such asynchronous operation. ERCOT is currently performing a study that compares its single CONTROL AREA performance against that of the former ten CONTROL AREA

operations. Initial results of that study show that while the ten CONTROL AREAS *individually* met CPS2 standards, the *aggregate* CPS2 performance of the ten CONTROL AREAS did not, and was actually below that of the current single CONTROL AREA.

Current Operating Reliability

ERCOT does not believe that Frequency control within its new single CONTROL AREA INTERCONNECTION is less reliable as a result of non-compliance with the CPS2 Standard following its conversion. ERCOT Interconnection frequency control has been, and continues to be, very reliable since that conversion.

The table below shows ERCOT's CPS2 performance for August through December 2000 as an INTERCONNECTION with ten Control Areas. The average CPS2 compliance was 74.82%. CPS2 compliance for ERCOT as a single control area for August 2001 was 83.88%, an improvement of approximately nine percentage points.

Single Control Area Frequency Performance

	% of Frequency Data Available	Supplier Of Frequency Data	Single Control Area CPS1 %	CPS2 %	Average of Absolute 1 min Averages Freq Deviation	Average of Absolute 10 min Averages Freq Deviation
August-00	79	ERCOT	140.99	76.50	0.011978483	0.008299971
September-00	100	ERCOT	134.89	76.02	0.012366	0.009495
September-00	100	REIT HLP	135.91	77.01	0.012221795	0.008443165
October-00	23	ERCOT	199.68	76.90	0.013910426	0.00857111
October-00	100	REIT HLP	114.01	78.58	0.014621429	0.008120248
November-00	65	ERCOT	105.19	67.20	0.015061531	0.010523159
December-00	60	ERCOT	192.59	72.60	0.013428052	0.009330552
Average (See Note 1)			134.71	74.82	0.013439915	0.009062032
August-01	None (See Note 2)	None (See Note 2)	127.30	83.88		

Note 1: Weighted Average Based on ERCOT for August, September November and December and REIT for October.
Note 2: From ERCOT CPS report. ERCOT is working on providing frequency data for August 2001.

Effective until:

1. **No longer needed, or**
2. **Replaced by NERC Reliability Standard**

Waiver Request – Financial Inadvertent Settlement

Organizations

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool

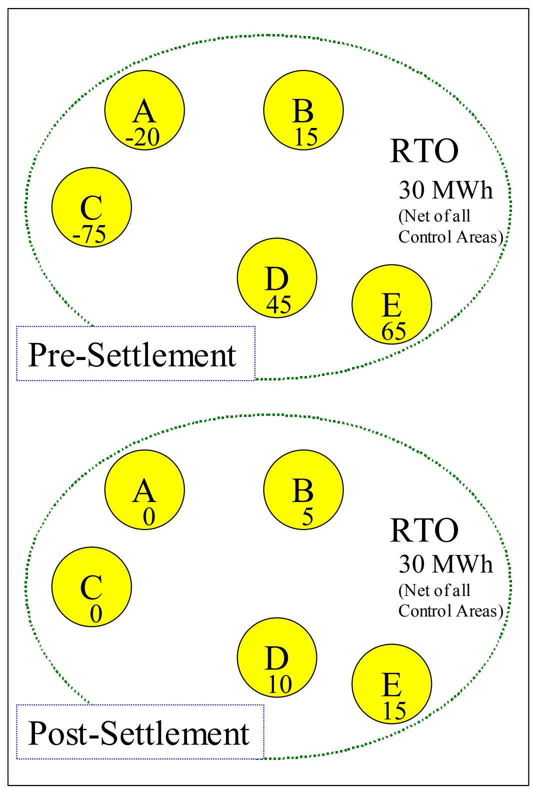
Operating Policy

The CONTROL AREA participants of the Alliance RTO, Midwest ISO and Southwest Power Pool are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," to allow financial settlement of INADVERTENT INTERCHANGE within a RTO. The Midwest ISO has filed with the FERC Service Schedule 4 – Energy Imbalance, which contains a provision for financial settlement of INADVERTENT INTERCHANGE between the Midwest ISO CONTROL AREAS.

The RTO Organizations request a waiver from Policy 1, Section F:

5.2. **Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

Explanation



The participant CONTROL AREAS ask for a waiver from the requirement that the method of INADVERTENT payback within the RTO be agreed upon by all Regions within the Eastern INTERCONNECTION. Approval of this waiver would allow the participant CONTROL AREAS to adjust their hourly INADVERTENT through an RTO financial settlement process while assuring that the method of INADVERTENT payback will not affect non-participant CONTROL AREAS or the net INADVERTENT owed to the INTERCONNECTION. For reliability reporting, such as for the NERC Area Interchange Error (AIE) report, the participant CONTROL AREAS will continue to report the actual "on-peak" and "off-peak" INADVERTENT INTERCHANGE incurred in all hours. In addition, they will also maintain an adjusted INADVERTENT account to reflect the amount owed to the INTERCONNECTION after financial settlement within the RTO.

Under the financial settlement process, the RTO will determine the amount of INADVERTENT INTERCHANGE that can be financially settled between the CONTROL AREAS within the RTO while assuring that the net INADVERTENT INTERCHANGE for the combined CONTROL AREAS under the RTO will not change.

The example below and to the right reflects five CONTROL AREAS within a RTO. Before financial settlement of INADVERTENT INTERCHANGE the net of the five CONTROL AREAS' INADVERTENT INTERCHANGE is 30 MWh. As the net INADVERTENT for the hour is positive, all negative INADVERTENT is financially settled within the RTO with 30 MWh remaining to be reported by the CONTROL AREAS post-settlement. Through this process the INADVERTENT INTERCHANGE account with the INTERCONNECTION is unaffected.

Control Area	*Inadvertent*	*Settlement Schedule**	*Adjusted Inadvertent*
A	-20	-20	0
B	15	10	5
C	-75	-75	0
D	45	35	10
E	65	50	15
RTO Net	**30**	**0**	**30**
* MWh settled financially			

Current Operating Reliability

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 1F5.2

Other payback methods. Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

Conditions:

The Control Area Participants within the scope of the RTO that financially settle inadvertent will report both the unadjusted and adjusted quantities on the Inadvertent Interchange summary.

Effective until replaced by the applicable Reliability Standard.

Waiver Request – Tagging Dynamic Schedules and Inadvertent Payback

Entity
Western Electricity Coordinating Council – Operating Committee

Policy
Policy 3 "Interchange"

Waiver Requested
Add the following to third bullet under Policy 3 Section A.2.1 – Deference to the WECC where Dynamic Interchange Schedules are of known amounts by the sending and receiving control areas, have existing transmission capacity, and the Transmission Providers are aware of the amounts which are exempt from being tagged.

Add the following to the fourth bullet under Policy 3 Section A.2.1 – Deference to the WECC where existing procedure require notification of bilateral payback to be made via the WECC Messaging network where all parties are notified. Amounts less than or equal to 25 megawatts per hour are not required to be tagged.

Explanation
The WECC Operating Committee and Interchange Scheduling and Accounting Subcommittee requested a waiver to Policy 3 to tagging requirements for bilateral inadvertent interchange payback schedules and dynamic schedules.
The tagging requirements simply do not apply to operations in the Western Interconnection. Adding a tagging requirement for dynamic schedules will add a burden on scheduling entities and will not provide a substantial benefit. CA and TP have real-time scheduling information on dynamic schedules.

Unilateral inadvertent payback is not allowed in the WECC.

Effective until:

1. **No longer needed, or**
2. **Replaced by NERC Reliability Standard**

Waiver Request – Scheduling Agent

Organization

The Control Area participants of:

- Alliance RTO
- Midwest ISO
- Southwest Power Pool
- Grid South

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 1, "Generation Control and Performance," and Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a SCHEDULING AGENT:

SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 1 Version 1a, "Generation Control and Performance," and Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Standards

Policy 1

- Policy 1F, "Inadvertent Interchange Standard"

Requirements

Policy 1

- 1G 1.1 – Control Surveys (AIE Survey)

Policy 3

- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)

Explanation

The SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Intra-RTO TRANSACTIONS would be handled with the SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a SCHEDULING AGENT to act on their behalf with all ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.

2. Include the SCHEDULING AGENT in the SCHEDULING PATH of all INTERCHANGE TRANSACTIONS effectively placing the RTO SCHEDULING AGENT in the role of an INTERMEDIARY CONTROL AREA with respect to INTERCHANGE TRANSACTION management.

3. Manage any "scheduling error" attributable to the SCHEDULING AGENT and internalize this scheduling error into the INADVERTENT INTERCHANGE accounts of the participating CONTROL AREAS.

4. Include the SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to an INTERMEDIARY CONTROL AREA.

By establishing a SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will:

   a. Allow the participant RTO CONTROL AREAS to implement INTERCHANGE SCHEDULES directly with the SCHEDULING AGENT, significantly reducing the scheduling, coordination and checkout contacts of the participants.

   b. Allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

4. A RTO participant CONTROL AREA is only involved in the coordination of an INTERCHANGE SCHEDULE if it is the SOURCE or SINK CONTROL AREA in the INTERCHANGE TRANSACTION. For example, the CONTROL AREAS within a RTO would be transparent to the transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across a RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within/through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 1F4.1

INADVERTENT INTERCHANGE Accounting. Adjacent CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

> **Daily accounting**. Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to the hourly integrated values of:
>
> - NET INTERCHANGE SCHEDULE
> - NET ACTUAL INTERCHANGE

Conditions:

The Control Area Participants shall designate their Scheduling Agent to be responsible for agreeing to NET INTERCHANGE SCHEDULE values with Adjacent Control Areas or other Scheduling Agents. The Control Areas will continue to calculate INADVERTENT INTERCHANGE based on Interchange Transactions sourcing and sinking in those Control Area.

Policy 1F4.2

Monthly accounting. Each CONTROL AREA shall use the agreed-to Daily accounting data to compile the monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. **[Refer to "Inadvertent Interchange Accounting Training Document"]**

Conditions:

The Control Area Participants shall use, on a monthly basis, the NET INTERCHANGE SCHEDULES with their RTO Scheduling Agent in compiling Inadvertent Interchange reports. The RTO Scheduling Agent shall use all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.

Policy 1F6

INADVERTENT INTERCHANGE summary. Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, "INADVERTENT INTERCHANGE Energy Accounting Practices and Dispute Resolution Process." These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

Conditions:

The Control Area Participants shall continue to report NET ACTUAL INTERCHANGES with their physically interconnected Control Areas, but will report NET INTERCHANGE SCHEDULES only with their RTO Scheduling Agent. The RTO Scheduling Agent will report all NET INTERCHANGE SCHEDULES with adjacent Control Areas or other Scheduling Agents.

Policy 1G

Surveys. The CONTROL AREAS in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee:

> **AIE survey.** Area Interchange Error survey to determine the CONTROL Areas' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to submit the AIE survey for Control Areas within the RTO's boundary in a form similar to that proposed under Policy 1F.

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6

Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions: The applicants clarify that for pass-through transactions, the RTO Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY CONTROL AREA, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4

INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:

The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY CONTROL AREA with respect to all transactions and schedules involving the RTO or its Control Areas.

Approved by Operating Committee

July 16 – 17, 2003

Waiver Request – Enhanced Scheduling Agent

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed RTO Scheduling Process to meet the RTO obligations under Order 2000, simplify TRANSACTION information requirements for market participants, reduce the number of parties with which CONTROL AREA operators must communicate, and provide a common means to tag TRANSACTIONS within and between RTOs.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, "Interchange," to accommodate a RTO Scheduling Process. The RTO participants propose the following definition of a ENHANCED SCHEDULING AGENT:

ENHANCED SCHEDULING AGENT. A function with the authority to act on behalf of one or more CONTROL AREAS for INTERCHANGE SCHEDULE implementation including creation, confirmation, approval, check-out and associated INADVERTENT INTERCHANGE accounting.

The following specific sections of NERC Policy 3, Version 4, "Interchange," are affected by the RTO Scheduling Process proposed in this Waiver request:

Policy 3

- 3A 4 – Interchange Transaction Implementation (Assessment)
- 3A 6 – Interchange Transaction Implementation (Implementation)
- 3B 4 – Interchange Schedule Implementation (Confirmation)

Explanation

The ENHANCED SCHEDULING AGENT would be the single point of contact for all external, non-participating CONTROL AREAS or other SCHEDULING AGENTS with respect to scheduling INTERCHANGE into, out of, or through the RTO. Through TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the single point of contact between each participating CONTROL AREA similar to an ADJACENT CONTROL AREA. Into or Out Of TRANSACTIONS would be handled with the ENHANCED SCHEDULING AGENT acting as the SINK or SOURCE CONTROL AREA, respectively. This reduces the number of entities with which a given CONTROL AREA must coordinate, and should improve the management of INTERCHANGE TRANSACTIONS and INTERCHANGE SCHEDULES.

The RTO CONTROL AREA participants propose to:

1. Designate their RTO as a ENHANCED SCHEDULING AGENT to act on their behalf with all external ADJACENT CONTROL AREAS with respect to implementation of INTERCHANGE SCHEDULES, including scheduling, confirmation and after-the-fact checkout.

2. Include the Enhanced Scheduling Agent in the Scheduling Path of all Interchange Transactions in the role of Control Area (Intermediary, Source, or Sink as appropriate) with respect to Interchange Transaction management.

3. Include the ENHANCED SCHEDULING AGENT in the reporting of NET SCHEDULED INTERCHANGE in INADVERTENT INTERCHANGE reporting similar to a CONTROL AREA.

By establishing a ENHANCED SCHEDULING AGENT function for the CONTROL AREAS under a multi-party regional agreement or transmission tariff, the following areas can be addressed and/or benefits achieved through the waiver approval:

1. NERC Policy 3B states that INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS. Approval of the waiver will allow CONTROL AREAS bordering a RTO to implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT rather than the RTO participant CONTROL AREAS. For example, a CONTROL AREA interconnected with three CONTROL AREAS within a RTO under the ENHANCED SCHEDULING AGENT, would implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT, rather than the three CONTROL AREAS, significantly reducing its scheduling, coordination and checkout contact requirements.

2. Seams issues associated with multiple CONTROL AREA scheduling paths existing between two adjacent RTOs are minimized by allowing the market to view the seam as a single interface between two RTOs, coordinated by their SCHEDULING AGENTS.

3. Rather than being faced with an ever-increasing number of ADJACENT CONTROL AREAS to implement INTERCHANGE SCHEDULES with and include in INADVERTENT Accounting, any CONTROL AREAS that implement INTERCHANGE SCHEDULES with the ENHANCED SCHEDULING AGENT remain unaffected as the RTO grows in Scope and Scale.

4. The CONTROL AREAS within a RTO served by a ENHANCED SCHEDULING AGENT would be transparent to a transmission customer as the customer reserves transmission service and submits an energy schedule for pass-through transactions across said RTO.

5. By simplifying the transaction implementation process for both participant and non-participant CONTROL AREAS, automation of INTERCHANGE confirmation, scheduling and checkout with the ENHANCED SCHEDULING AGENT becomes achievable.

The proposal simplifies the transaction tagging process for market participants in that there is no longer a need to designate a specific CONTROL AREA contract path within or through the RTO where there may, in fact, be several parallel contract paths possible. The specific scheduling processes implemented between participating CONTROL AREAS within the RTO are internalized and transparent to the market, but will not violate any reliability criteria.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A4

The CONTROL AREA Assesses:

- Transaction start and end time
- Energy profile (ability of generation maneuverability to accommodate)
- Scheduling Path (proper connectivity of ADJACENT CONTROL AREAS)

Conditions: The Control Area Participants will allow the RTO Scheduling Agent to assess proper connectivity on the Scheduling Path.

Policy 3A6

Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

Conditions: The applicants clarify that the Enhanced Scheduling Agent shall assume the role and responsibilities of the INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with regard to Policy 3, and the individual RTO's Control Areas do not appear in the Scheduling Path on the tag. The RTO's Control Areas will not incorporate these transactions into a schedule in their EMS.

Policy 3B4

INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the CONFIRMATION and IMPLEMENTATION of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

INTERCHANGE SCHEDULE agreement. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- Interchange Schedule start and end time
- Ramp start time and rate
- Energy profile

Conditions:

The obligation with respect to confirmation and implementation of INTERCHANGE SCHEDULES under Policy 3B 4 shall be satisfied by the confirmation of all schedules with the Scheduling Agent. The Scheduling Agent shall assume the role and responsibilities that would otherwise be considered that of an INTERMEDIARY, SOURCE, or SINK CONTROL AREA as appropriate with respect to all transactions and schedules involving the RTO or its Control Areas.

Additional Conditions

The Operating Committee approved this waiver on July 16, 2003 with the following condition:

> "With NERC and appropriate regional representation, audit and confirm the Midwest ISO's readiness to perform the functions detailed in the enhanced scheduling agent and energy flow information waivers before they go into effect."

Waiver Request – Energy Flow Information

Approved by Operating Committee

July 16 – 17, 2003

Organization

The Control Area participants of:

- Midwest ISO

Operating Policy

The CONTROL AREA participants request approval of this Waiver to implement a proposed multi-Control Area Energy Market, simplify TRANSACTION information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for reliability analysis, curtailments, reloads, reallocations, and Network and Native Load (NNL) redispatch requirements.

The participants are requesting a Waiver of specific provisions of NERC Policy 3, “Interchange,” to accommodate a Multi-Control Area Energy Market. This waiver would also apply in the event that Control Areas in the RTO are combined into fewer Control Areas or into one Control Area. This wavier is required to realize the benefits of a LMP market operation in the RTO Area while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Process. It is understood that the level of granularity of information provided to Reliability Coordinators must not be reduced or reliability will be negatively impacted. The RTO participants propose the use of the concepts contained within the PJM/MISO paper, “Managing Congestion to Address Seams,” to meet the requirements specified in Policy 3.

The following specific sections of NERC Policy 3, Version 5.1, “Interchange,” are affected by the RTO Scheduling Process proposed in this Waiver request:

Requirements

Policy 3

- 3A 2.1 – Application to Transactions

Explanation

Policy 3 currently requires that several different types of transactions be tagged; specifically, it requires that any transactions involving Control Area to Control Area transfers must be tagged in order that Reliability Coordinators may review them as necessary to ensure system reliability.

The Midwest ISO intends to begin operating a multi-Control Area Energy Market in the near future. In so doing, the Midwest ISO will be scheduling net energy transfers between their various Control Area members based on a dynamically calculated, security-constrained economic dispatch. Bilateral transactions and transactions into or out of the RTO will continue to be tagged as appropriate. Net Control Area interchanges resulting from the market dispatch will simultaneously sum to zero within the MISO market. These market dispatch instructions do not correspond to traditional bilateral transactions between Control Areas. Instead, they can be viewed as a method to economically dispatch all generation within the Midwest ISO market. Each Control Area’s net interchange resulting from market dispatch is matched simultaneous with all the other Control Areas in the market. Rather than a specific Control Area assigned to receive this net market interchange, all Control Areas net interchanges in the market will be adjusted to sum to zero. Tagging this market interchange into bilateral transactions would be arbitrary and not accurate. Therefore, the Midwest ISO proposes that rather than supply Reliability Coordinators with tags, they instead be allowed to provide Reliability Coordinators with equivalent information that allows the same analyses and procedures to operate as would exist if tags had been entered.

Under this proposal, the Midwest ISO will establish a set of Coordinated Flowgates, which will be determined through the use of several studies, that represents all flowgates significantly impacted by the Midwest ISO's operation of their Energy Market. Further, the Midwest ISO will provide Reliability Coordinators the following information every 15 minutes:

- Total Flows attributed to Midwest ISO market operations for all Coordinated Flowgates
- Flows attributed to Midwest ISO NNL for all Coordinated Flowgates
- Flows attributed to Midwest ISO Economic Dispatch for all Coordinated Flowgates

This information will be provided for both current hour and next hour, and will be used to communicate to Reliability Coordinators the amount of flows to be considered as the result of firm and non-firm service on the various Coordinated Flowgates.

Additionally, every hour the Midwest ISO will submit to Reliability Coordinators a set of data describing the marginal units and associated participation factors for generation within the Midwest ISO market footprint. 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 Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Finally, the Midwest ISO will submit for each of its Control Areas estimated Interchange and Load for each hour of the day. This will be submitted on a day-ahead basis as well as an hour ahead basis. This data will be used by Reliability Coordinators to perform forward-looking security analyses.

Current Operating Reliability Implications

There are no reliability implications from this waiver.

Policy Conditions for Waiver Recommendation

Policy 3A.2.1

Application to TRANSACTIONS. All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service[1] shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA).
- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA). **[See also, Policy 1E2 and 2.1, "Disturbance Control Standard"]**

Conditions: The Midwest ISO must provide equivalent information regarding their market operations to Reliability Authorities as would be extracted from a transaction tag. Specifically, the Midwest ISO must provide 1.) Flows on significantly impacted flowgates, with indications as to firmness of those flows, in order that curtailments, reload, and reallocations may be directed by Reliability Coordinators as needed 2.) Marginal Units within the market footprint, in order that Reliability Coordinators may evaluate impacts of potential changes in dispatch within the market footprint 3.) Control Area Interchange and Load forecasts, in order that Reliability Coordinators may analyze the interconnected transmission system on a proactive basis

[1] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

Approved by Operating Committee.

March 23–25, 2004

Waiver Request – Enhanced Congestion Management (Curtailment/Reload/Reallocation)

Organization

The control area participants of:

- Midwest ISO, Inc.
- PJM Interconnection, L.L.C.

Operating Policy

The control area participants request approval of this waiver to implement a proposed multi-Control Area Energy Market, simplify TRANSACTION information requirements for market participants, and provide a means for providing Reliability Coordinators with appropriate information for security analysis and curtailments/reloads/reallocations and redispatch requirements.

The participants are requesting a waiver of specific provisions of the following NERC policies and appendices to accommodate a Multi-Control Area Energy Market.

This waiver would also apply in the event that applicant control areas are combined into fewer control areas or into one control area. This waiver is required to realize the benefits of a LMP market operation while increasing the level of granularity of information provided to the NERC Transmission Loading Relief Procedure. The applicant control areas propose the use of the concepts contained within the PJM/MISO paper, “Managing Congestion to Address Seams,” to meet the requirements specified in Policy 9 and its related appendixes.

The processes proposed in this waiver request affect the following specific sections of NERC Policy 9:

- **Appendix 9C1B.C (How the IDC Handles Reallocation)**,
- **Appendix 9C1B.C Attachment B – Timing Requirements (IDC Calculations and Reporting Requirements)**, and
- **Appendix 9C1.G (Transaction Curtailment Formula)**
- Appendix 9C1B “Interchange Transaction Reallocation During TLR Levels 3a and 5a”

For the purposes of clarity, this waiver describes many actions as those of the “RTO.” It should be noted that “RTO” refers to the market-operating entity in which the applicant control areas participate. Associated with this waiver are two distinct entities: 1.) Midwest ISO, and 2.) PJM Interconnection.

Assignment of Sub-Priorities

Requirements

Policy 9 – Appendix 9C1B

- 9C1B.C
- 9C1B.C.Attachment B

Explanation

The **"IDC Calculations and Reporting Requirements"** section of **Appendix 9C1B.C, Attachment B – Timing Requirements of Policy 9** states that "In a TLR Level 3a the INTERCHANGE TRANSACTIONS using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status."

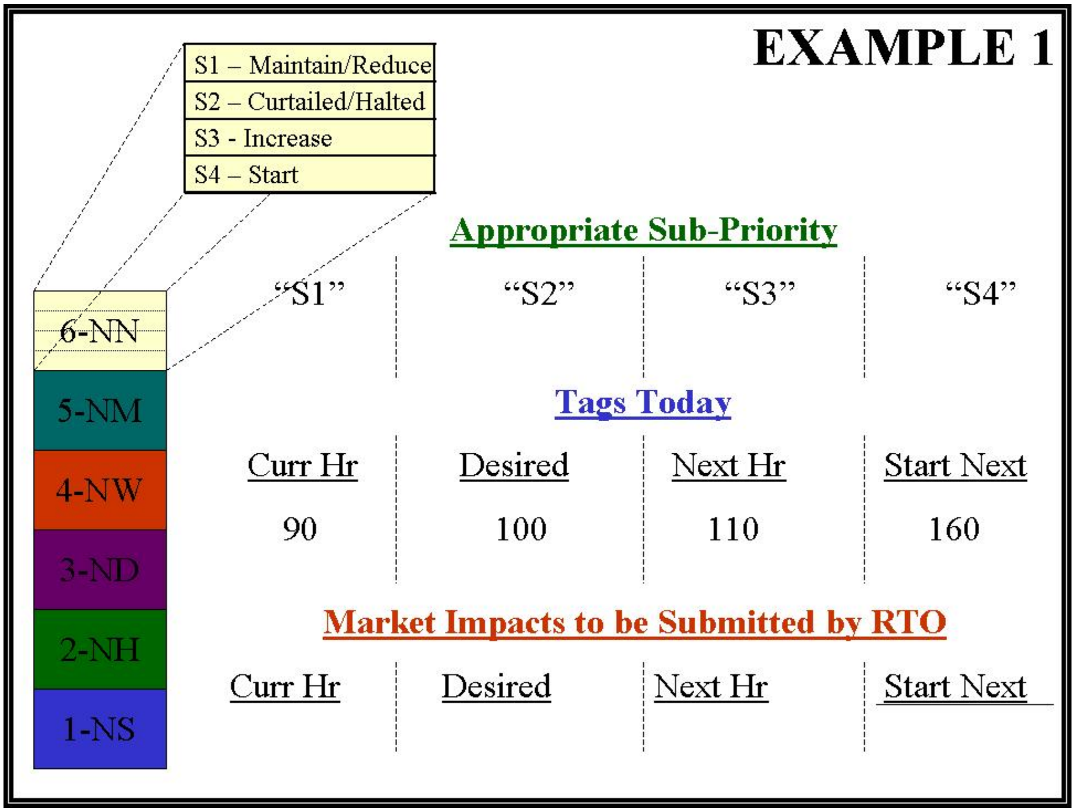
The RTO intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[1] that is associated with the operation of the RTO market. This energy is identified as "market flow".

These market flow impacts for current hour and next hour will be separated into their appropriate priorities[2] and provided to the IDC by the RTO. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional "tags", the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, the RTO proposes that for the purposes of reallocation, a sub-priority (S1 thru S4) be assigned to these market flow impacts by the NERC IDC, using the same parameters as would be used if the impacts were in fact tagged transactions — as detailed in NERC **Policy 9, Appendix 9C1, Attachment B – Timing Requirements (IDC Calculations & Reporting Requirements)**. *See Example 1 Below*

[1] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM Paper "Managing Congestion to Address Seams" White Paper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

[2] See the PJM/MISO Paper "Managing Congestion to Address Seams" for details on how these priorities will be assigned


EXAMPLE 1
S1 – Maintain/Reduce
S2 – Curtailed/Halted
S3 - Increase
S4 – Start
6-NN
5-NM
4-NW
3-ND
2-NH
1-NS
Appropriate Sub-Priority
"S1"
"S2"
"S3"
"S4"
Tags Today
Curr Hr
Desired
Next Hr
Start Next
90
100
110
160
Market Impacts to be Submitted by RTO
Curr Hr
Desired
Next Hr
Start Next

Pro Rata Curtailment of Non-Firm Market Flow Impacts

Requirements

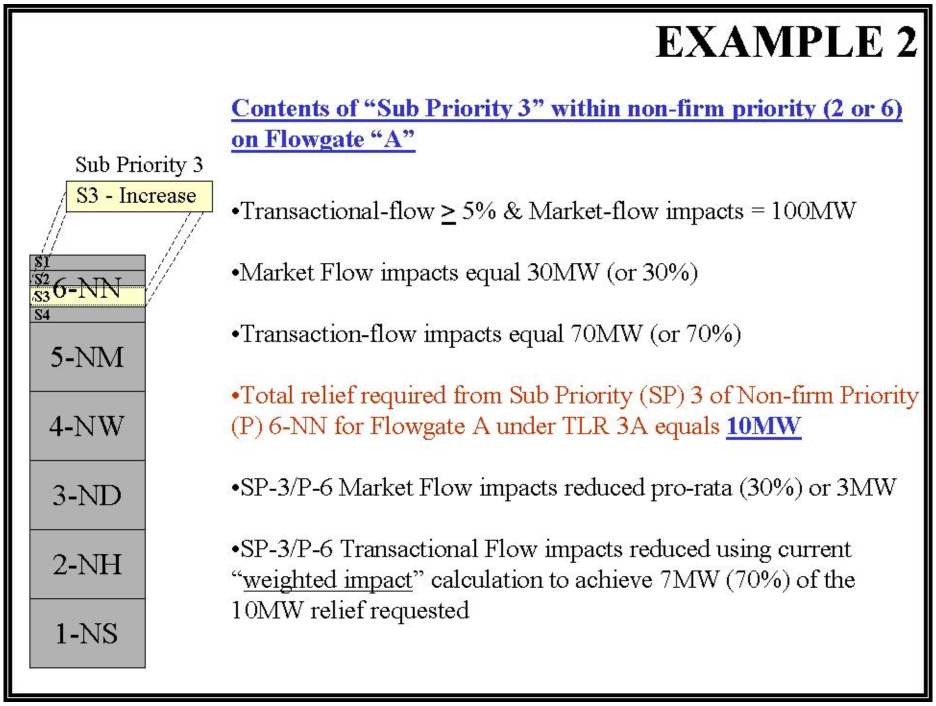
- **Appendix 9C1.G** (Transaction Curtailment Formula)

Explanation

NERC Policy 9, Appendix 9C1.G (Transaction Curtailment Formula) details the formula used to apply a weighted impact to each non-firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC. For the purpose of curtailment, we propose that the non-firm market flow impacts (Priorities 1 thru 6) submitted to the IDC by the RTO be curtailed pro rata as is done for INTERCHANGE TRANSACTIONS using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in **Policy 9 Appendix 9C1.G (Transaction Curtailment Formula)** will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC would be curtailed pro rata under this proposal, the impacting non-firm tagged transactions could still use the existing processes to assign the weighted impact value. “Example 2” (below) illustrates how this would be accomplished.



NNL Calculation

Requirements

- **Appendix 9C1.F** (Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service)
- **Parallel Flow Calculation Procedure Reference Document – Section C** (Calculation Method)

Explanation

Policy 9 – Appendix 9C1.F and the **Parallel Flow Calculation Procedure Reference Document – Section C** currently require that the "Per Generator Method Without Counter Flow" methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each control area.

The RTO intends to use a "Market Flow Calculation" methodology to calculate the portion of parallel flows on all facilities included in the RTO's "Coordinated Flowgate List"[3] due to NI service or service to NL of each control area.

---

[3] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO will perform the four studies (described in the MISO/PJM paper "Managing Congestion to Address Seams," Version 3.2) to

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 sum of the maximum generating capacity at a bus is greater than 20 MW. The market flow calculations will use all positively impacting flows down to 0% with no threshold. Counter flows will not be included in the market flow calculation.
- 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" method, while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force. Counter flows are also calculated and tracked in order to account for and recognize that the either the positive market flows may be reduced or counter flows may be increased to provide appropriate relief on a flowgate. 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 RTO's market area footprint to be considered in the market flow calculation. However, units outside of the RTO's market area will not be considered when those units will have tags associated with their transfers.

These NNL values will be provided to the IDC to be included and represented with the calculated NNL values of all non-RTO control areas for the purposes identifying and obtaining required NNL relief across a flowgate in congestion under a TLR Level 5A/5B.

5% Curtailment Threshold

Requirements

- **Appendix 9C1B –** Item **A.2**

determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).

Explanation

Policy 9 – Appendix 9C1B – Item A.2 states that "Only those INTERCHANGE TRANSACTIONS at or above the Curtailment Threshold for which a TLR 2 or higher is called are affected by the Reallocation procedure." The curtailment threshold stated in this section is "5%".

The RTO intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List"[4] that is associated with the operation of the RTO Market. This energy is identified as "Market Flow"

The RTO intends to provide to the IDC any market flows with an impact of greater than 0% on a coordinated flowgate. These market flows will then be represented and made available for curtailment under the appropriate TLR Levels. Hence, for the purposes of curtailment and reallocation, the RTO proposes that the impact threshold the RTO will observe for its market flows across any flowgate in the RTO Coordinated Flowgate List will be **0%** instead of **5%.**

The reason for this is that because of the size and scope of a large non-tagged energy market, such as the multi-control area market that the RTO is proposing, an impact of less than 5% on a flowgate could still represent a large amount of the total capacity of that flowgate. Therefore, to limit the Curtailment Threshold on these market flows to 5% could result in a Reliability Coordinator's inability to obtain the amount of relief that is needed to prevent the flowgate from exceeding its operating limits.

Below is an example of how a market flow curtailment threshold of less than 5% could substantially contribute to congestion on a flowgate:

Example:

- Energy market flows of 1,000 MW impact Flowgate A by 4% — or 40 MW
- Flowgate A operating limit is 100 MW
- Fully 40% of the flow across Flowgate A is not identified and represented in the IDC, and therefore not available for curtailment under the TLR process.

Current Operating Reliability

There are no reliability implications from this waiver.

[4] The RTO will conduct sensitivity studies to determine which external flowgates (outside the RTO's footprint) are significantly impacted by the market flows of the RTO's control zones (currently the control areas that exist today in the IDC). The RTO will perform the 4 studies (described in the MISO/PJM "Managing Congestion to Address Seams" Whitepaper Version 3.2) to determine which external flowgates the RTO will monitor and help control. An external flowgate selected by one of these studies will be considered a Coordinated Flowgate (CF).