Joint Operating Agreement
Between the
Midcontinent Independent System Operator, Inc.
And
Southwest Power Pool, Inc.
(DECEMBER 11, 2008)

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This Joint Operating Agreement ("Agreement") dated this 1st day of December, 2004, by and between Southwest Power Pool, Inc. ("SPP") an Arkansas not-for-profit corporation having a place of business at 201 Worthen Drive, Little Rock, AR 72223, and the Midcontinent Independent System Operator, Inc. ("MISO"), a Delaware non-stock corporation having a place of business at 720 City Center Drive, Carmel, Indiana 46032. SPP and MISO may be individually referred to herein as "Party" or collectively as "Parties".

WHEREAS, SPP is a North American Electric Reliability Corporation ("NERC") Regional Reliability Organization and an independent provider of reliability coordination, tariff administration, and scheduling services to its customers and interconnected member electric systems in the Southwest part of the United States;

WHEREAS, SPP has filed a petition with the Federal Energy Regulatory Commission ("FERC") for recognition as a Regional Transmission Organization ("RTO"), and is developing processes and systems to operate energy imbalance, congestion management, and other ancillary service markets in a phased approach;

WHEREAS, MISO is the RTO that provides operating and reliability functions in portions of the Midwest and Canada. MISO also administers the MISO Tariff for transmission and other services on its grid, and is developing processes and systems to operate markets to facilitate day-ahead and real-time energy transactions and financially firm transmission rights;

WHEREAS, FERC has ordered each Party to develop mechanisms to address inter-regional coordination;

WHEREAS, on February 27, 2004, the Parties entered into the System Operation, Planning and Market Development Memorandum of Understanding ("MOU"), which provides for the establishment of a Seams Agreement Coordinating Committee to develop recommendations on coordination activities that will improve reliability and reduce barriers to electricity trading within the regions and to negotiate a Joint Operating Agreement that will contractually bind the Parties to these coordination activities; and

WHEREAS, in accordance with good utility practice and in accordance with the directives of FERC, the Parties seek to establish exchanges of information and establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, and to give effect to other matters required by FERC;

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, the receipt of which hereby is acknowledged, the Parties hereby agree as follows:

2.1.1 “AC” shall mean Alternating Current.

2.1.2 “AFC” shall mean Available Flowgate Capability.

2.1.3 “BA” shall mean Balancing Authority.

2.1.4 “BAA” shall mean Balancing Authority Area.

2.1.5 “CBM” shall mean Capacity Benefit Margin.

2.1.6 “CFR” shall mean Code of Federal Regulations.

2.1.7 “CIM” shall mean Common Information Model.

2.1.8 “DC” shall mean Direct Current.

2.1.9 “EHV” shall mean Extra High Voltage.

2.1.10 “EMS” shall mean the Energy Management Systems utilized by the Parties to manage the flow of energy within their RC Areas.

2.1.11 “ERAG” shall mean the Eastern Interconnection Reliability Assessment Group that is charged with multi-regional modeling

2.1.12 “FERC” shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

2.1.13 “ICCP”, “ISN” and “ICCP/ISN” shall mean those common communication protocols adopted to standardize information exchange.

2.1.14 “IPSAC” shall mean Inter-regional Planning Stakeholder Advisory Committee.

2.1.15 “IROL” shall mean Interconnection Reliability Operating Limit.

2.1.16 “JPC” shall mean Joint Planning Committee.

2.1.17 “kV” shall mean kilovolt of electric potential.

2.1.18 “LBA” shall mean Local Balancing Authority.

2.1.19 “LBAA” shall mean Local Balancing Authority Area.

2.1.20 “MMWG” shall mean the NERC working group that is charged with multi-regional modeling.

2.1.21 “MVAR” shall mean megavolt amp of reactive power.

2.1.22 "MW" shall mean megawatt of real power.

2.1.23 "MWh" shall mean megawatt hour of energy.

2.1.24 "NAESB" shall mean the North American Energy Standards Board or its successor organization.

2.1.25 "NERC" shall mean the North American Electricity Reliability Corporation or its successor organization.

2.1.26 "NSI" shall mean net scheduled interchange.

2.1.27 "OASIS" shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet.

2.1.28 "OATT" shall mean the applicable Open Access Transmission Tariff.
2.1.29 "PMAX" shall mean the maximum generator real power output reported in MWs on a seasonal basis.

2.1.30 "PMIN" shall mean the minimum generator real power output reported in MWs on a seasonal basis.

2.2.31 "PSS/E" shall mean Power System Simulator for Engineering.

2.1.32 "QMAX" shall mean the maximum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.33 "QMIN" shall mean the minimum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.34 "RC" shall mean Reliability Coordinator.

2.1.35 "RCF" shall mean Reciprocal Coordinated Flowgate.

2.1.36 "RCIS" shall mean the Reliability Coordinator Information System.

2.1.37 "RTO" shall mean Regional Transmission Organization.

2.1.38 "SACC" means the Seams Agreement Coordinating Committee, established in the Memorandum of Understanding between the Parties.

2.1.39 "SCADA" shall mean Supervisory Control And Data Acquisition.

2.1.40 "SDX System" shall mean the system used by NERC to exchange system data.

2.1.41 "SOL" shall mean System Operating Limit.

2.1.42 "TFC" shall mean Total Flowgate Capability.

2.1.43 "TLR" shall mean Transmission Loading Relief.

2.1.44 "TOP" shall mean Transmission Operator.

2.1.45 "TRM" shall mean the Transmission Reliability Margin.

2.2.1 "a & b multipliers" shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC. The "a" multiplier is applied to TRM in the planning horizon to determine non-firm AFC. The "b" multiplier is applied to TRM in the operating horizon to determine non-firm AFC. The "a & b" multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 "Affected System" shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

2.2.3 "Agreement" shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

2.2.4 "Attaining Balancing Authority" or "Attaining BA" shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time.

2.2.5 "Attaining Balancing Authority Area" or "Attaining BAA" shall mean the Balancing Authority Area, as that term is defined in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time, of the Attaining Balancing Authority.

2.2.6 "Attaining Reliability Coordinator" or "Attaining RC" is the entity that is responsible for Reliable Operation of the Bulk Electric System, as those terms are defined in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time, for the Attaining Balancing Authority.

2.2.7 "Available Flowgate Capability" shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

2.2.8 "Balancing Authority" shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time. For MISO references to BA may be applicable to a BA and/or an LBA.

2.2.9 "Balancing Authority Area" shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. For MISO references to BA may be applicable to a BAA and/or an LBAA.

2.2.10 "Bulk Electric System" shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.11 "Confidential Information" shall have the meaning stated in Section 18.1.

2.2.12 "Congestion Management Process" means that document which is Attachment 1 to this Agreement as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.13 "Coordinated Flowgate(s)" shall mean a Flowgate impacted by an Operating Entity as determined by one of the five studies detailed in Section 3 of the attached document entitled "Congestion Management Process." For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.14 "Coordinated Operations" means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.15 "Coordinated System Plan" shall have the meaning stated in Section 9.3.

2.2.16 "Economic Dispatch" shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.17 "Effective Date" shall have the meaning stated in Section 13.1.

2.2.18 "Extra High Voltage" shall mean 230 KV facilities and above.

2.2.19 "Facilities Study" shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.20 "Feasibility Study" shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.21 "Firm Flow" shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.22 "Firm Flow Limit" shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate based on procedures defined in Sections 4 and 5 of the Congestion Management Process (Attachment 1 of the Joint Operating Agreement).

2.2.23 "Flowgate" shall mean a representative modeling of facilities or group of facilities that may act as significant constraint points on the regional system.

2.2.24 "Intellectual Property" shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.25 "Interconnection Service" shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.26 "Interconnection Study" shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.27 "Interconnected Reliability Operating Limit" shall mean a System Operating Limit that if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.28 "Intermittent Generation" shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.29 "Interregional Coordination Process" shall mean the market-to-market coordination document incorporated herein as Attachment 2 to this Agreement, as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.30 "Interregional Planning Stakeholder Advisory Committee" shall have the meaning given under Section 9.1.2.

2.2.31 "Interregional Project" shall have the meaning given under Section 9.6.3.1.

2.2.32 "Local Balancing Authority" shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority reliability standards defined for its local area within the MISO Balancing Authority Area, and (ii) a party (other than MISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority reliability standards for which the LBA is responsible.

2.2.33 “Local Balancing Authority Area” shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.34 “Market” shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.35 “Market-Based Operating Entity” shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.36 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.

2.2.37 “Market Monitor” shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.

2.2.38 “Memorandum of Understanding” shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement dated February 27, 2004.

2.2.39 “MISO” has the meaning stated in the preamble of this Agreement.

2.2.40 “Native Balancing Authority” or “Native BA” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time.

2.2.41 “Native Balancing Authority Area” or “Native BAA” shall mean the Balancing Authority Area, as that term is defined in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time, of the Native Balancing Authority.

2.2.42 “Native Reliability Coordinator” or “Native RC” is the entity that is responsible for Reliable Operation of the Bulk Electric System, as those terms are defined in the NERC Glossary of Terms Used in NERC Reliability Standards as may be amended from time to time, where the pseudo-tie is physically located.

2.2.43 “Network Upgrades” shall have the meaning as defined in the MISO and SPP tariffs.

2.2.44 “NERC Compliance Registry” shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.45 “Notice” shall have the meaning stated in Section 18.10.

2.2.46 “Operating Entity” shall mean 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.

2.2.47 “Outages” shall mean the planned unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.48 “Party” or “Parties” refers to each party to this Agreement or both, as applicable.

2.2.49 “Purchasing-Selling Entity” shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.50 “Reciprocal Coordination Agreement” shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.51 “Reciprocal Coordinated Flowgate(s)” shall mean a Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. A RCF is:

- A Coordinated Flowgate that is (a) (i)within the operational control of a Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as RC, and (b) affected by the transmission of energy by the Parties or by either Party or both Parties and one or more Reciprocal Entities; or
- A Coordinated Flowgate that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to Congestion Management Process reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or
- A Coordinated Flowgate that is designated by agreement of both Parties as a RCF.

2.2.52 “Reciprocal Entity” shall mean any entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.53 “Reliability Coordinator” shall mean that party approved by NERC to be responsible for reliability for a RC Area.

2.2.54 “Reliability Coordinator Area” (“RC Area”) shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.55 “SCADA Data” shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Standard TOP-005.

2.2.56 "SPP" Has the meaning stated in the preamble of this Agreement.

2.2.57 "State Estimator" shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.58 "System Impact Study" shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.59 "System Operating Limit" shall mean the value (such as MW, MVAR, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

2.2.60 "Third Party" refers to any entity other than a Party to this Agreement.

2.2.61 "Third Party Operating Entity" shall refer to a Third Party 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.

2.2.62 "Total Flowgate Capability" shall mean 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 capability 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.

2.2.63 "Transmission Issue" shall mean transmission needs driven by reliability, economic, and/or public policy requirements.

2.2.64 "Transmission Loading Relief" shall mean the procedures used in the Eastern Interconnection as specified in NERC Standards IRO-006 and the NAESB Business Practices WEQ-008.

2.2.65 "Transmission Operator" shall mean the entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

2.2.66 "Transmission Owner" shall mean a Transmission Owner as defined under the Parties' respective tariffs.

2.2.67 "Transmission Reliability Margin" shall mean that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.2.68 "Transmission Service Provider" shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.69 "Transmission System Emergencies" are conditions that have the potential to exceed or would exceed an IROL.

2.2.70 "Voltage and Reactive Power Coordination Procedure" are the procedures under Article XI for coordination of voltage control and reactive power requirements.

Section 2.3.1 No Interpretation Against Drafter. In addition to their roles as RCs, and the functions and responsibilities associated therewith, the Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

Section 2.3.2 Incorporation of Preamble and Recitals. The Preamble and Recitals of this Agreement are hereby incorporated into the terms and conditions of this Agreement and made a part thereof.

Section 2.3.3 Meanings of Certain Common Words. The word "including" shall be understood to mean "including, but not limited to." The word "Section" refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word "Article" refers to articles of this Agreement.

Section 2.3.4 Certain Headings. Certain sections of Articles IV and V contain descriptions of the purpose or requirements stated in those sections. These statements of purpose are to provide background information to assist in the interpretation of the requirements. The absence of a stated purpose with respect to any requirement does not diminish the enforceability of the requirement. If a provision in Articles IV and V is not delineated as "purpose," "background," or "definition," it is a requirement.

Section 2.3.5 NERC Reliability Standards. All activities under this Agreement will meet or exceed the applicable NERC reliability standards as revised from time to time.

Section 2.3.6 NAESB Business Practices. All activities under this Agreement will meet or exceed the applicable NAESB business practices as revised from time to time.

Section 2.3.7 Scope of Application. Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Transmission Owner for which it administers transmission service and, in addition, each BA for which it serves as RC.

MISO and SPP will use this Joint Operating Agreement, to the extent applicable, for the coordination of Transmission Service Provider, BA, RC and other functions for which they may have registered in the NERC Compliance Registry. The Parties have agreed to the coordination and exchange of data and information under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to these systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement. The Parties agree that the objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

Purpose: Sharing data is necessary to facilitate effective coordination of operations and to maintain regional system reliability while assuring the maximum commercial flexibility for market participants.

Requirements: The Parties will exchange the following types of data and information:

(a) Real-Time and Projected Operating Data;
(b) SCADA Data;
(c) EMS Models;
(d) Operations Planning Data; and
(e) Planning Information and Models.

Each Party shall provide the data identified in items (a) through (e) above to the other Party with respect to all Transmission Owners for which it administers transmission service and BAs for which it acts as RC on the Effective Date and during the term of this Agreement, whether or not such an entity is contemplated as of the Effective Date.

The Parties also shall exchange such information as the Market Monitors of SPP and MISO may request in order to facilitate monitoring in accordance with the Parties' respective FERC-approved market monitoring plans.

To facilitate the exchange of all such data, each Party will designate to the other Party's designated representative a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by notice to the other Party's designated representative.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. If any required data exchange format has not been agreed upon as of the Effective Date, or if a Party determines that an agreed format should be revised, a Party shall give Notice of the need for an agreed format or revision and the Parties will jointly seek to complete development of the format within thirty (30) days of such Notice.

The Parties agree that various components of the data exchanged under this Section is Confidential Information and that:

(a) The Party receiving the Confidential Information shall treat the information in the same confidential manner as its governing documents require it treat the confidential information of its own members and market participants.

(b) The receiving Party shall not release the producing Party's Confidential Information until expiration of the time period controlling the producing Party's disclosure of the same information, as such period is described in the producing Party's governing documents from time to time. As of the Effective Date, this period is six (6) months with respect to bid or pricing data and seven (7) calendar days for transmission data identified in 4.1.1(a) after the event ends.

(c) All other prerequisites applicable to the producing Party's release of such Confidential Information have been satisfied as determined by the producing Party.

Requirements: The Parties will exchange two categories of operating data: real-time information and projected information, as follows.

(a) The real–time operating information consists of:

- Generation status of the units in each Party's RC Area;
- Transmission line status;
- Real-time loads;
- Scheduled use of reservations; and
- TLR information, including calculation of Market Flows.

(b) Projected operating information consists of:

- Merit order for generators in the Parties' Markets;
- Maintenance schedules for generators and transmission facilities in either of the Party's RC Area;
- Transmission service reservations reflecting firm purchase and sales;
- Independent power producer information including current operating level, projected operating levels, outage start and end dates;
- The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments;
- Points of interconnection between the two Parties that will be permanently removed or added (to the soonest extent possible, this information will be shared by the Party responsible for the action shortly before taking such action); and
- The planned and actual start-up testing and operational start-up or change dates for any permanently added, removed or significantly altered generation units.

Background: NERC Standard TOP-005, Attachment 1 "Electric System Reliability Data," describes the types of data that Transmission Operators, Balancing Authorities and Purchasing-Selling Entities are expected to provide, and Reliability Coordinators are expected to share with each other as explained in Standard TOP-005, "Operational Reliability Information."

Requirements:

(a) The Parties shall exchange requested transmission power flows, measured bus voltages and breaker equipment statuses of their bulk transmission facilities via ICCP or ISN.

(b) Each Party shall accommodate, as soon as practical, the other Party's requests for additional existing ICCP/ISN bulk transmission data points, but in any event no more than one (1) week after the request has been submitted.

(c) Each Party shall respond, as soon as practical, to the other Party's requests for additional, unavailable ICCP/ISN bulk transmission data points, but in any event no more than two (2) weeks after the request has been submitted, with an expected availability target date for the requested data.

(d) The Parties will comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.

(e) The Parties shall exchange SCADA Data consisting of:

- (i) Status measurements 69 kV and above (breaker statuses) (as available and required to observe for reliability as the respective Parties may determine);
- (ii) Analog measurements 69 kV and above (flows and voltages) (as available and required to observe for reliability as the respective Parties may determine);
- (iii) Generation point measurements, including generator output for each unit in MW and MVARS, as available;
- (iv) Load point measurements, including bus loads and specific loads at each substation in MW and MVARS, as available;
- (v) BAA net interchange;
- (vi) BAA instantaneous demand;
- (vii) BAA operating reserves; and
- (viii) Identification of other real-time data available through ICCP/ISN.

Purpose: EMS models contain detailed representations of the transmission and generation configurations within each RTO and neighboring systems. The Parties depend upon EMS models for reliability coordination and market operations. The regular exchange of models is to ensure that each Party is using current and up-to-date representations of the other Party.

Requirements: The Parties will exchange their detailed EMS models once a year in CIM or another mutually agreed-upon electronic format, but shall provide each other with updates of the model information in an agreed-upon electronic format as new data becomes available. This yearly exchange will include the ICCP/ISN mapping files, identification of individual bus loads, seasonal equipment ratings and one-line drawings that will be used to expedite the model conversion process. The Parties will also exchange updates that represent the incremental changes that have occurred to the EMS model since the most recent update.

Pseudo-Tie Modeling Requirements: The Native BA and the Attaining BA shall coordinate modeling in accordance with the rules of the Native BA and Attaining BA, respectively, for modeling the pseudo-tie. If either the Native BA or Attaining BA do not have the necessary information to support modeling the pseudo-tie, modeling data will be requested from the entity seeking to pseudo-tie. This includes coordination of specific technical details for each pseudo-tie. Section 12.2 provides more detail on pseudo-tie requirements.

Purpose: Operations planning data, which defines how a system was planned and built, is basic information needed to coordinate planning and operations between the Parties.

Requirements: Upon the written request of a Party, the other Party shall provide the information specified in Sections 4.1.4.1 through 4.1.4.10 inclusive, or any components thereof. Each request shall specify the information sought and the frequency upon which it would be provided. A Party receiving a request under this Section shall provide the information promptly to the extent the information is available to the Party. Operations planning data is not generally considered confidential but to the extent any of this data overlaps previously defined operating data in Section 4.1.2, it is considered Confidential Information.

(a) Flowgate definitions including seasonal TFC, TRM, CBM, a & b multipliers;
(b) Flowgates to be added on demand;
(c) List of Coordinated Flowgates;
(d) List of Flowgates to recognize when processing transmission service (if different than list of Coordinated Flowgates); and
(e) Requirements under Section 5.1.7.

(a) Daily list of all reservations, hourly increment of new reservations;
(b) List of reservations to exclude;
(c) Requirements under Sections 5.1.4 and 5.1.5; and
(d) List of long-term firm reservations not subject to rollover rights.

Each Party will meet a minimum periodicity for calculating and making available AFCs to each other. The minimum periodicity depends on the service being offered. Each Party will provide the following AFC data to the other Party:

(a) Hourly for first seven (7) days posted at a minimum, once per hour;
(b) Daily for days eight (8) through thirty-one (31) posted at a minimum, once per day; and
(c) Monthly for months two (2) through eighteen (18) posted at a minimum, once per month.

(a) Hourly for next seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through eighteen (18) submitted once a day;

(b) Identity of the BAA or zone within a BAA for which the forecast is given;

(c) Indicate whether this forecast includes transmission system losses, and if it does, indicate what the percent losses are;

(d) Identify non-conforming loads;

(e) Indicate how municipal entities, cooperatives and other entity loads are treated. Indicate whether they are included in the forecast. If so, indicate the total load or net load after removing other entity generation; and

(f) Requirements under Section 5.1.6.

(a) Unit owner, bus location in model;
(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;
(c) Station auxiliaries to extent gross generation has been reported; and
(d) Regulated bus, target voltage and actual voltage.

(a) Network Integration Transmission Service Specifications;
(b) Designated Network Resource information; and
(c) To the extent that Designated Network Resources operate between the Markets administered by the Parties:
    (i) Indication of treatment as pseudo tie or dynamic/static schedules;
    (ii) Rules for sharing output between joint owners; and
    (iii) Transmission arrangements.

Section 4.1.4.7 - Balancing Authority Area Net Interchange from Reservations and Tags:

(a) Any grandfathered agreements that do not appear in OASIS; and

(b) In cases where tags and reservations cannot be used to develop BAA or zone net interchange, then provide hourly NSI for all the BAAs within the Markets.

(a) List of dynamic schedules;
(b) Identification of dynamic schedules that are being used to move load between the Parties’ respective Markets; and
(c) Requirements under Section 5.1.11.

(a) Phase shifters;
(b) Market-dispatchable demand response resources greater than 50MW;
(c) DC lines; and
(d) Back-to-back AC/DC converters.

(a) Generation outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.1;

(b) Transmission outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.3; and

(c) Notification of all forced outages of both generation and transmission resources, not to exceed 30 minutes after they are identified.

Requirements: Each Party shall provide the other Party with data to enable the other Party independently to verify the results of the calculations that determine the market-to-market settlements under this Agreement. A Party supplying data shall retain that data for two years from the date of the settlement invoice to which the data relates, unless there is a legal or regulatory requirement for a longer retention period. The method of exchange and the type of information to be exchanged pursuant to this Section 4.2 shall be specified in writing and posted on the Parties' websites. The posted methodology shall provide that the Parties will cooperate to review the data and mutually identify or resolve errors and anomalies in the calculations that determine the market-to-market settlements. If one Party determines that it is required to self report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Agreement, the reporting Party shall inform, and provide a copy of the self report to, the other Party. Any such report provided by one Party to the other shall be "confidential information" as defined in this Agreement.

Requirements: Each Party shall bear its own cost of providing information to the other Party pursuant to Section 4.1 and 4.2.

Purpose: The calculation of AFC is a forecast of transmission capability that may be available for use by transmission customers. Use of transmission capability in one system can impact the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the AFC values for its own transmission system. The exchange of data related to calculation of AFC is necessary to assure reliable coordination, and also to permit either Party to determine if, due to lack of transmission capability, it must refuse a transmission reservation in order to avoid potential overloading of facilities.

As of the Effective Date, the Parties use the SDX System to exchange the status of generators rated greater than 50 MW, outages of all interconnections and other transmission facilities operated at greater than 100 kV, and peak load forecasts. This system has the capability to house hourly data for the next seven (7) days, daily data for the next thirty one (31) days, weekly data for the next month, and monthly data for the next three calendar years. Continued use of this tool, and associated commitments under this Agreement, will assure the Parties' abilities to make reliable calculations efficiently.

Requirements: Each Party shall provide the other with projected status of generation availability over the next twelve (12) months. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each "return date" of a generator from a scheduled or forced outage. If the status of a particular generator of less than 50 MW is used within a Party's AFC calculation, the status of this unit shall also be supplied.

Purpose: Dispatch information combined with unit availability information permits each Party to develop a reasonably accurate dispatch for any modeled condition. This methodology is more advantageous than scaling all available generation to meet generation commitments within an area and then increasing all generation uniformly to model an export, or uniformly decreasing all generation to model an import. While excluding nuclear generation or hydro units from this scaling would provide some level of refinement, this approach is inadequate to identify transmission constraints and determine rational AFC values. The exchange of typical generation dispatch order or generation participation factors of all units on a BAA basis and other data under this Agreement will permit each Party to appropriately model future transmission system conditions.

Requirements: As necessary to permit a Party to develop a reasonably accurate dispatch for any modeled condition, each Party will provide the other Party with a typical generation dispatch order or the generation participation factors of all units on an affected BAA basis. The generation dispatch order will be updated as required by changes in the status of the unit; however, a new generation dispatch order need not be provided more often than prior to each peak load season.

Requirements: Each Party will provide the other Party with the projected status of transmission outage schedules above 100 kV over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the “outage date” and “return date” of a transmission facility from a scheduled or forced outage.

Purpose: Because interchange schedules impact the short-term use of the transmission system, exchange of schedule data is necessary to determine the remaining capability of the transmission system as well as to determine the net impact of loop flow.

Requirements: Each Party will make available to the other its interchange schedules/NSI, as required to permit accurate calculation of AFC values. Due to the high volume of this data, the Parties shall either post this data to a mutually agreed upon site for downloading or utilize tag dump information by the other Party as required by its own process and timing requirements.

The impacts of pseudo-ties will be included in the Attaining BA's market flow impacts for purposes of congestion management procedures. Neither MISO, nor SPP nor the entity seeking to pseudo-tie shall tag or request to tag the energy flows from a pseudo-tie into the Attaining BAA.

Purpose: Beyond the operating horizon, the impacts of existing transmission service requests are also necessary for the calculation of AFC for future time periods. Inasmuch as a transmission reservation is a right to use and not an obligation to use the transmission system, there is no certainty that any particular reservation will result in a corresponding interchange schedule. This is especially true considering that the *pro forma* OATT 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, at a given time, purchased all transmission reservations on a particular source-to-sink path. A further complication is that the duration or firmness of the one portion of the reservation may not be the same as the remaining portion. Since, prior to scheduling, it is difficult to associate reservations involving multiple Transmission Providers that may be used to complete a single transaction, double counting in the AFC determination process is a possibility. It is therefore acknowledged that certain reservations respecting one Party are not required to be incorporated into transmission models developed by the other Party.

Requirements:

(a) Each Party will make available to the other Party, on a mutually agreed upon site, actual transmission service requests information for integration into each Party's AFC determination process.

(b) Each Party will develop practices for modeling transmission service requests, including external requests, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. Each Party will provide the other Party with the procedures developed and implemented to model intra-Party requests, requests on external parties, and reservation netting.

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

(d) Each party shall maintain a list of long-term firm reservations that are not subject to rollover rights and accordingly treat them in their process.

Requirements: The Parties will exchange forecasted peak load data for each period in accordance with the NERC reliability standards and NAESB business practices (*e.g.*, daily, weekly, and monthly). Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. This is in accordance with the FERC's regulations at 18 C.F.R.[1] § 37.6(b)(4)(iv). For the next seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a BAA or zone basis, with further granularity provided to reflect load forecasts by company within the BA.

[1] The Code of Federal Regulations (CFR) is the codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government.

Purpose: Data exchange 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 and procedures are necessary to assure that each Party respects the other Party's Flowgates.

Requirements:

(a) The Parties will exchange Firm and Non-firm AFC for all relevant Flowgates.

(b) Each Party will accept or reject transmission service requests based upon projected AFCs applicable to both Parties' Flowgates and to RCFs; and

(c) Each Party will limit approvals of requests for transmission service between the parties, including roll-over transmission service, so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the Parties, provided that firm transmission service customers retain the rollover rights and reservation priority granted to them under the applicable Party's OATT, and further provided that if explicitly stated in the applicable service agreement, a Party may limit rollover rights for new long-term firm service if there is not enough AFC to accommodate rollover rights beyond the initial term.

Requirements: The Parties will exchange (seasonal, normal and emergency) TFC as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system.

Requirements: Each Party shall consider in its TFC and AFC determination process all Flowgates: (i) that may initiate a TLR event and that are significantly impacted by its transactions, or (ii) as mutually agreed between the Parties. A Party's transactions are deemed to significantly impact another Party's Flowgates if they have a response factor equal to or greater than the response factor cut-off used by the owning Party. The Parties in their AFC determination and transmission service processing efforts shall use the response factor cut-off that the owning/operating Party uses for its Flowgates.

Section 5.1.10 Configuration/Facility Changes (for power system model updates).

Requirements:

(a) A mechanism will be maintained between the Parties to ensure that all significant system changes of a neighbor are incorporated in each Party's AFC calculation model. Although this information and a host of very detailed data are included in the MMWG/ERAG cases, this data exchange mechanism will address the 'major' changes that should be included in the AFC calculation models in a more timely manner. This data exchange will occur no less often than prior to each peak load season.

(b) In addition, the Parties agree to exchange AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this exchange.

Requirements: Each Party agrees to provide the other Party with the actual amount and future projection of dynamic schedule flows. All dynamic schedule flows and tags will be submitted in accordance with NERC reliability standards and NAESB business practices.

Requirements: Each Party shall make transmission capability available for reserve sharing by including the significant impacts of the other Party's generation outages in its TRM values. The Parties will coordinate and share the necessary information for the determination of these impacts as necessary.

If the Parties have contract paths to the same entity, the combined contract path capacity will be made available for use by both Parties. No Party will exceed the combined contract path capacity. Any use of the combined contract path capacity shall be subject to all NERC reliability requirements and the terms of the Congestion Management Process and Section 5.3. This will not create new contract paths for either Party that did not previously exist. SPP will not be able to deal directly with companies with which it does not physically or contractually interconnect and MISO will not be able to deal directly with companies with which it does not physically or contractually interconnect.

If a Party exceeds or anticipates that it will exceed its own contract path capacity and thus rely on combined contract path capacity during normal operating conditions as a result of changes in RTO membership that affect configuration which occurred on or after December 19, 2013, the Parties will negotiate an arrangement for appropriate compensation of the other Party's contract path capacity. For purposes of negotiating a compensation provision, a Party shall provide notice to the other Party six months prior to engaging in such usage, and the Parties shall negotiate in good faith to arrive at terms for compensation for such service. For purposes of negotiating a compensation agreement for the integration of MISO South, the Parties agree that the Settlement Agreement filed and accepted in Docket Nos. ER14-1174, *et al.* is the compensation agreement between the Parties. Any new agreement reached under this Section 5.3 shall have no impact on the Settlement Agreement filed and accepted in Docket No. ER14-1174, *et al*. Notwithstanding the foregoing, in the event a Party exceeds its own contract path capacity in circumstances other than those specifically described in this Section 5.3, nothing in this Agreement shall be interpreted as authorizing or precluding compensation to the other Party.

In the event that, after good faith negotiation, the Parties are unable to reach mutual agreement on the terms of the shared contract path usage described in Sections 5.2 and 5.3, the Parties shall submit unresolved issues to the dispute resolution, as provided in Section 14.2 of this Agreement. The sharing of contract path capacity pursuant to Section 5.2 shall be permitted during the pendency of the dispute, subject to all NERC reliability requirements and terms of the Congestion Management Process. Compensation and other terms resolved through the dispute resolution process or any FERC proceeding initiated as a result of a failure to reach agreement shall be retroactive to the date usage commenced.

In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC and calculations of firmness for real-time operations applicable to the Party's Coordinated Flowgates. Additionally, each Party agrees to respect the allocations defined by the allocation process set forth in the Congestion Management Process. The Parties will establish and finalize the process and timing for exchanging their respective AFC calculations and Firm Flow calculations/allocations with respect to all RCFs. The Parties' capabilities and real time actions shall be governed by and in accordance with the Congestion Management Process.

In the event redispatch occurs in order to coordinate congestion management under Section 6.1 or subparts thereof, including redispatch necessary to respect the other Party's Flowgate, as set forth in Article XII, the Party responsible for the flow that required the redispatch shall bear the costs of the redispatch.

Each Party shall make transmission capability available for reserve sharing by either redispatching its Flowgates or holding TRM for generation outages in the other Party's system. The Party responsible for making transmission capability available for the reserve sharing obligation shall bear the costs of the redispatch to the extent the costs may be recovered under such Party's OATT.

Each Party will maintain a detailed model of the other Party's system for operations and planning purposes. Each Party's model will be sufficiently detailed to properly honor that Party's Coordinated Flowgates. Furthermore, each Party will populate its model with credible data and will keep such models up-to-date.

The Parties have an interregional outage coordination process for coordinating transmission and generation outages to ensure reliability and to promote optimally efficient market operations. The Parties agree to the following with respect to transmission and generation outage coordination.

Upon a Party's request, the projected status of generation and transmission availability will be communicated between the Parties, subject to data confidentiality agreements. All available information regardless of scheduled date will be shared. The Parties shall exchange the most current information on proposed outages and provide a timely response on anticipated impacts of proposed outages.

The Parties agree that this information will be shared promptly upon its availability, but no less than daily and more often as required by system conditions. The Parties shall utilize a common format for the exchange of this information. The information includes the owning Party's facility name; proposed outage start date and time; proposed facility return date and time; date and time when a response is needed from the impacted Party to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

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

Section 7.1.2 Evaluation and Coordination of Transmission and Generation Outages.

The Parties will analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party's outage analysis will consider the impact of its critical outages on the other Party's system reliability, in addition to its own.

On a weekly basis, daily if requested by one of the Parties, the operations planning staff of each Party shall jointly discuss any outages to identify 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 Party has the authority to cancel the other Party's outage (except transmission facilities interconnecting the two Parties' transmission systems). However, the Parties 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 Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved and make every effort to act on behalf of the other Party to effect the requested schedule change. If this change cannot be accommodated, the Party with the outage shall notify the impacted Party. 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.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known (not to exceed thirty (30) minutes). The Parties will evaluate the impact of emergency and forced outages on the Parties' 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 Party will consider the impact of these changes on the other Party's system reliability, in addition to its own. The Parties 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.

Joint emergency procedures are essential due to the highly dependent nature of facilities under different authorities. The Parties are committed to reliable operation of the transmission system under normal conditions, and will work closely together during emergency situations that place the stability of the transmission system in jeopardy.

In the event either Party declares a system emergency with respect to its system, the Parties agree to provide emergency assistance and to facilitate obtaining emergency assistance from a Third Party. The Parties will coordinate respective actions to provide immediate relief. The Parties will notify each other of emergency maintenance and forced outages that would have a significant impact on the other Party as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work together to develop remedial steps as necessary

In the interest of maintaining system stability and providing prompt response to problems that may arise, the Parties agree that in situations where there is an actual IROL violation and/or the system is on the verge of imminent collapse, and when there is already an existing Emergency Procedure or Operating Guide, both Parties and the affected operating entity will communicate and coordinate simultaneously via conference calls. Subsequent to such anomalous operations, the requesting Party will file a lessons learned report for the Parties and operating entities. This lesson learned report may assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

The Parties will work together and with the BAs under their purview to jointly develop and commit to additional emergency procedures as the need for such procedures arises. These procedures shall be reviewed annually by the Parties.
Transmission System Emergencies may be implemented when, in the judgment of either Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that it becomes necessary for either Party to declare a Transmission System Emergency for a Flowgate that is in close electrical proximity to both of the Parties' areas, both Parties will take action(s) in kind to address the situation that prompted the Transmission System Emergency. These actions may include:

(a) Curtailment of equivalent amounts of firm point-to-point transactions within both Parties;
(b) Redispatching of generation within both Parties; and
(c) Load shedding within both Parties.

In situations where an actual IROL violation exists and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing Emergency Procedure or Operating Guide, the Parties will receive and carry out the instruction of the affected Party, or communicate the instruction to the affected entity within their own boundary, or utilize conference call capabilities to allow simultaneous coordination/communication between the Parties and the affected entity.

No delay shall take place during the event, except in instances where the requested action will result in a more serious condition on the transmission system, or instances where, in the judgment of either Party, the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system. All occurrences of this kind may be reviewed by either or both Parties after the fact.

In a situation where a SOL violation exists within the regions of the Parties, or for the next contingency would exist, the Parties will work together as necessary, following good utility practices, and take action in kind as required to address the situation.

As the RC for each respective region, each Party has the responsibility and authority to coordinate with the other Party and direct emergency action on the part of generation or transmission to protect the reliability of the network and shall do so if required to resolve emergency conditions in the other Party’s region.

Effective restoration procedures require coordination and communication at all levels of the Parties' organizations and their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other RCs, in order to restore the transmission system as safely and efficiently as possible. In order to enhance restoration operations between the Parties, both Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both Parties are positioned to better assist the other in a real restoration

Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. As such, the Parties will coordinate operations in accordance with good utility practice in order to maintain stable voltage profiles throughout the respective Party's zones of operations.

When any one Party identifies an overload/emergency situation that may impact the other Party's system and the other Party's results/systems do not observe a similar situation, both Parties will operate to the most conservative result until the Parties can identify the reasons for these difference(s).

Each Party is to bear its own costs of compliance with emergency energy procedures, except as the applicable Tariff may otherwise require. If a Party is required to purchase emergency energy in order to address the flow of the other Party, then the other Party shall be required to provide compensation.

The SACC shall form a Joint Planning Committee (JPC) comprised of representatives of the Parties' respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, alternating every two years, to designate a Chairman of the JPC to serve a two-year calendar term beginning in 2014. The first two-year chairmanship shall commence on January 1, 2014 and end December 31, 2015. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings.

For the purpose of interregional transmission planning coordination, the JPC shall meet no less than twice per year. The JPC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

The JPC is the decision making body for coordinated interregional transmission planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide guidance and recommendations to the JPC. The JPC is responsible for all aspects of coordinated interregional transmission planning, including the development of a Coordinated System Plan.

The JPC will determine if a Coordinated System Plan study should be performed for any particular interregional study cycle as part of the annual Transmission Issues review performed pursuant to Section 9.3.2. If it is determined that a transmission study should be performed, the JPC with input from the IPSAC, will perform a Coordinated System Plan study pursuant to Section 9.3.3. A Coordinated System Plan study will be completed no less than every two years.

The JPC will verify that the results of the study are accurate and meet the expectations of the JPC based on the study scope.

In addition, the JPC responsibilities include:

i. For studies of proposed transmission interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JPC will direct the use of applicable power system models, such as to those to support power flow analyses, short circuit analyses, and dynamic stability analyses in order to assess potential impacts of flows along the seams.
ii. Assure that the regional models used in the interregional evaluation by each planning region are sufficiently coordinated, including joint review of each region's respective models.
iii. Coordinate all planning activities under this Article IX including the exchange of data.
iv. Support the review by any federal or provincial agency of elements of the Coordinated System Plan.
v. Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.
vi. Establish working groups as necessary to provide adequate review and development of the regional plans.

Establish a schedule for the rotation of responsibility for data management, coordination of IPSAC meetings including producing meeting minutes, coordination of analysis activities, report preparation, and other activities.

The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective coordinated interregional planning.

While the JPC may have multiple representatives from each Party, each Party shall on matters requiring a vote of the JPC be permitted to cast one vote. For a matter to be approved by the JPC, both planning regions must vote in the affirmative, except as provided in sub-paragraph (ii) of the second paragraph of section 9.3.2.4.

Each Party shall maintain in its own website a webpage dedicated to the communication of information related to interregional transmission coordination procedures.

Under the direction of the JPC, the Parties shall coordinate on the documents and information that is posted to each Party's respective interregional coordination webpage to ensure consistency of information.

Each Party's interregional coordination webpage shall contain, at a minimum, the following information:

i. Link to this Joint Operating Agreement (JOA);
ii. Notice of scheduled IPSAC meetings;
iii. Links to materials for IPSAC meetings; and
iv. Documents relating to Coordinated System Plan studies.

The Parties shall form an IPSAC. The IPSAC shall facilitate stakeholder review and provide stakeholders the opportunity to advise the JPC on matters related to coordinated system planning for the development of the Coordinated System Plan. IPSAC meetings shall be facilitated by the JPC.

IPSAC participation is open to all stakeholders. All IPSAC meetings will be public. At an IPSAC meeting any stakeholder may provide comments or ask questions. For the purpose of interregional transmission coordination, the IPSAC shall meet no less than once per year. The IPSAC shall meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

The IPSAC will meet in the first quarter of the calendar year, or at an otherwise mutually agreeable date determined by the JPC, to review identified Transmission Issues and make a recommendation on whether a Coordinated System Plan study should be performed.

The IPSAC's primary role is to advise the JPC on all matters relating to the development of a Coordinated System Plan as established by this Article IX.

The IPSAC will provide input and a recommendation to the JPC as to whether a Coordinated System Plan study should be performed pursuant to Section 9.3.2. If it is determined by the JPC that a study should be performed, the IPSAC will provide input to the JPC during the performance of the Coordinated System Plan study pursuant to Section 9.3.3.

Each Party’s defined voting group shall represent one vote, and each Party’s respective voting group may provide a recommendation to the JPC on behalf of the IPSAC. The voting members of the SPP portion of the IPSAC are the members of the SPP Seams Steering Committee, along with a representative from each SPP Transmission Owner that interconnects to MISO but does not have a representative on the Seams Steering Committee. The voting members of the MISO portion of the IPSAC are the sector representatives from the MISO Planning Advisory Committee.

In support of interregional transmission planning coordination, each Party shall provide the other with the following data and information on an annual basis and will follow the stipulations for such exchange as noted below:

a) Powerflow models for projected system conditions for the planning horizon (up to the next ten (10) years) that include planned generation development and retirements, planned transmission facilities and seasonal load projections;

b) System stability models with detailed dynamic modeling of generators and other active elements;

c) Production cost models that include planned generation development and retirements, load forecasts, and planned transmission facilities;

d) Assumptions used in development of above powerflow, stability and production cost models; and

e) Contingency lists for use in powerflow, stability, and production cost analyses.

Models provided will be consistent with those used in the respective Party's planning processes. Formats for the exchange of data will be agreed upon by the JPC. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this JOA. The Parties agree to maintain the data and information received under Section 9.2.1 in accordance with each Party's applicable Critical Energy Infrastructure Information ("CEII") and confidentiality policies. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of Section 9.2 as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of each calendar year, unless Parties agree in writing to a different timeline.

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request as noted below:

(a) Any updates to data exchanged in accordance with Section 9.2.1:

(b) Short-circuit models for transmission systems:

(c) The regional plan document produced by the Party, the timing of each planned enhancement, estimated completion dates, and indications of the likelihood a system enhancement will be completed;

(d) The status of expansion studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies;

(e) Transmission system maps in electronic format for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties;

(f) Breaker diagrams for the specified portion(s) of the Party's transmission system;

(g) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies;

(h) Long-term or short-term reliability assessment documents produced by the Party and any operating assessment reports produced by the Party; and

(i) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

The Parties agree to maintain the data and information received under Section 9.2.2 in accordance with each Party's applicable CEII and confidentiality policies. Any data shared between the Parties that are market sensitive shall be clearly identified as such. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within thirty (30) calendar days from the date of such request or on a mutually agreed to schedule.

The primary purpose of coordinated system planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, address public policy requirements, improve operational performance, or enhance the efficiency of electricity markets. Any such expansions or enhancements shall be described in a Coordinated System Plan.

Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its agreements and open access transmission tariff ("OATT"). Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report and document the procedures, methodologies, and business rules that are utilized in preparing and completing this transmission planning report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party's OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

On an annual basis, the Parties agree to review Transmission Issues identified by each Party or any Third Party. During an ongoing Coordinated System Plan study, the Parties may review Transmission Issues identified by each Party or any Third Party upon agreement of the JPC. This annual review of Transmission Issues will be administrated by the JPC, in coordination with the IPSAC, to determine the need for a Coordinated System Plan study.

No later than thirty (30) calendar days prior to the annual IPSAC meeting, each Party and Third Parties shall submit Transmission Issues, and may include related transmission solutions, to the JPC that such Party or Third Party determines are appropriate for interregional evaluation, including the analysis to support the recommended Transmission Issues, for consideration by the JPC and IPSAC.

A notification of the annual IPSAC meeting for Transmission Issues review shall be placed on each Party's interregional coordination webpage, and circulated through applicable electronic distribution list(s), sixty (60) calendar days in advance of the annual IPSAC meeting inviting Third Parties to submit Transmission Issues, and may include any related transmission solutions, for interregional evaluation. All Third Party submissions must be received no later than thirty (30) calendar days prior to the annual IPSAC meeting. Each Party will distribute to the JPC Transmission Issues and supporting analysis submitted by Third Parties.

If a Third Party submits an identified Transmission Issue to the JPC, then that Third Party is responsible for providing a detailed description of the recommended Transmission Issue. These submissions shall be exchanged between the Parties' JPC representatives.

During the annual issues evaluation process, the IPSAC will meet no less than once. The IPSAC will meet to review identified Transmission Issues submitted to the JPC. If a second meeting is scheduled by the JPC, the IPSAC will review the determination of the JPC on the need to perform a Coordinated System Plan study.

The JPC shall schedule an IPSAC meeting to review the identified Transmission Issues annually, prior to the Coordinated System Plan study being performed. During an ongoing Coordinated System Plan study the JPC may schedule an IPSAC meeting to review the identified Transmission Issues upon agreement of the JPC. The JPC shall post any meeting materials to each Party's respective interregional coordination webpage fourteen (14) calendar days in advance of the meeting for the IPSAC review of identified Transmission Issues.

During the meeting to review identified Transmission Issues, the IPSAC shall review and discuss the identified Transmission Issues provided by the Parties and any Third Party to the JPC, including the analysis to support recommended issues for evaluation. Based on this review, the IPSAC will provide a recommendation to the JPC on the need to perform a Coordinated System Plan study. This IPSAC recommendation shall be determined by an IPSAC vote, in accordance with Section 9.1.2.3.

The IPSAC representatives for each Party may provide information to the JPC supporting their respective positions.

The JPC will review the recommendation from the IPSAC and all submitted Transmission Issues to determine the need for a Coordinated System Plan study. Within forty-five (45) calendar days after the IPSAC provides the recommendation to the JPC, the JPC will vote in accordance with Section 9.1.1.3 whether to perform a Coordinated System Plan study.

A Coordinated System Plan study shall be initiated by either of the following: (i) each Party in the JPC votes in favor of performing the Coordinated System Plan study; or (ii) if a Coordinated System Plan study was not initiated the previous year.

The JPC will document its determination of the need to perform a Coordinated System Plan study, including the recommendation of each Party and the IPSAC, which will be provided to the IPSAC through posting on each Party's interregional coordination webpage within thirty (30) calendar days after the JPC determination to perform a Coordinated System Plan study.

The JPC will agree to the start date of the Coordinated System Plan study, which shall not exceed 180 calendar days from the date of the JPC's determination to perform the Coordinated System Plan study.

Section 9.3.2.5 IPSAC Review of JPC Determination of the Need for a Coordinated System Plan Study

If a Party's JPC representative proposes to hold an IPSAC meeting to review the JPC's determination of the need to perform a Coordinated System Plan study, an IPSAC meeting shall be held within thirty (30) calendar days after the JPC's determination.

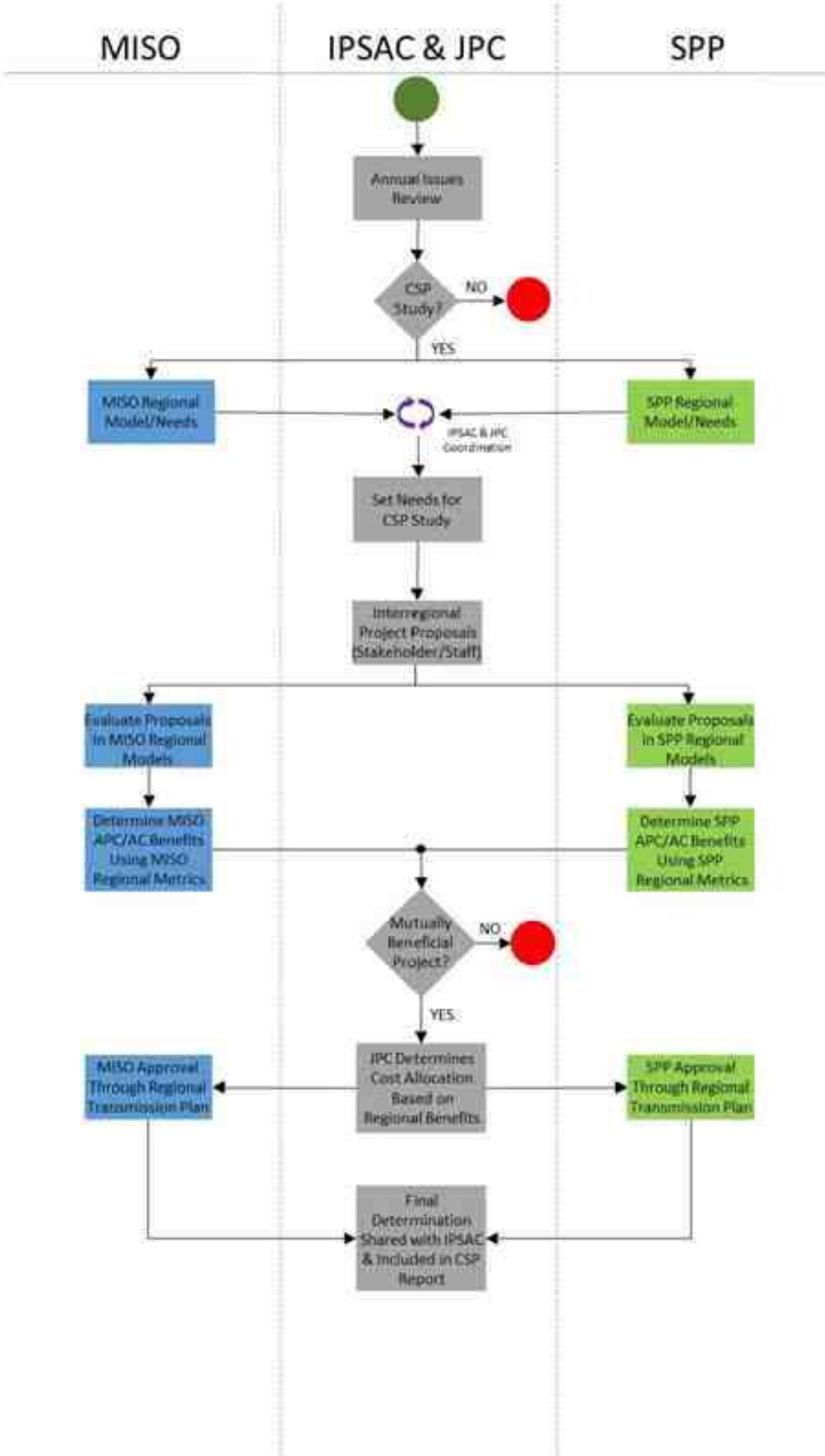
In the event a Coordinated System Plan study is initiated pursuant to Section 9.3.2.4, the study shall be performed in accordance with this Section 9.3.3.

Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan and each Party will have exclusive rights over their own planning process and results. Neither Party shall have the right, under this Section, to obtain financial compensation due to the impact of another Party's plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond.

At the beginning of the Coordinated System Plan study, the JPC will develop, with input from the IPSAC, the scope for the Coordinated System Plan study, which shall include, but is not limited to: 1) identification of Transmission Issues to be evaluated; 2) description of the respective model(s) that shall be used including assumptions and relevant futures and those futures' weightings; 3) types of analysis, which may include, but is not limited to, congestion analysis, reliability analysis, evaluation of public policy requirements, and stability analysis; 4) study timeline, which shall not exceed 18 months from the first IPSAC meeting discussing the study scope; and 5) deliverables. Upon mutual agreement, the JPC may amend the Coordinated System Plan study scope.

The specific Coordinated System Plan study process steps will depend on the type and scope of the study. The JPC shall provide the specific deadlines for each step in the Coordinated System Plan study following the JPC's decision to initiate such study.

Either Party may include an issue in the scope that was reviewed at the IPSAC annual Transmission Issues evaluation meeting pursuant to Section 9.3.2.


MISO
IPSAC & JPC
SPP
Annual Issues Review
CSP Study?
NO
YES
MISO Regional Model/Needs
SPP Regional Model/Needs
IPSAC & JPC Coordination
Set Needs for CSP Study
Interregional Project Proposals (Stakeholder/Staff)
Evaluate Proposals in MISO Regional Models
Evaluate Proposals in SPP Regional Models
Determine MISO APC/AC Benefits Using MISO Regional Metrics
Determine SPP APC/AC Benefits Using SPP Regional Metrics
Mutually Beneficial Project?
NO
YES
MISO Approval Through Regional Transmission Plan
JPC Determines Cost Allocation Based on Regional Benefits
SPP Approval Through Regional Transmission Plan
Final Determination Shared with IPSAC & Included in CSP Report

The JPC shall be responsible for facilitating the review and coordination of the appropriate respective regional model(s) that shall be used for the Coordinated System Plan study. The study models used by the JPC to perform all analysis related to the joint evaluation shall be consistent with the models and assumptions used for the regional planning cycles in which studied interregional transmission solutions would be included. Stakeholders may provide input on the regional model(s) developed for the Coordinated System Plan study through the IPSAC. Changes should not be made to the regional models simply because an interregional study is being performed.

The type of analysis that is performed during a Coordinated System Plan study shall be based on the Transmission Issues identified in the scope and the metrics used to determine the benefits of the solutions being evaluated. The potential solutions will be evaluated to determine if they address the identified Transmission Issue(s) and the benefits to each Party.

During the Coordinated System Plan study each Party may propose interregional solutions for evaluation. The JPC shall request through each Party's applicable distribution lists and each Party's respective interregional coordination webpage suggestions for transmission solutions from Third Parties to address the Transmission Issues identified in the Coordinated System Plan study. The proposed transmission solutions shall be considered by the JPC and reviewed with the IPSAC.

Section 9.3.3.4.1 Evaluating Potential Impact of Proposed Interregional Projects to Other Transmission Planning Regions

As part of the evaluation of any proposed Interregional Project, the Parties will determine whether the proposed Interregional Project has potential adverse impacts on the systems of other transmission planning regions. If the evaluation identifies any such potential adverse impact, the Parties will contact and coordinate with the other potentially affected transmission planning region on the further evaluation of the potential adverse impact(s).

Section 9.3.3.5 Interregional Project Recommendation Process

Interregional Project(s) identified in the Coordinated System Plan study will be evaluated by each Party through its respective regional processes and analyses. If both Parties determine a proposed Interregional Project(s) is beneficial to their respective region by satisfying the respective regional criteria and the criteria in Section 9.6.3 then the Interregional Project(s) and associated interregional cost allocation will be voted on by the JPC. If the JPC approves an Interregional Project(s), it will then be included in the respective regional transmission plans of the Parties and will be presented to the respective Parties' Board of Directors for approval and implementation.

In accordance with Section 9.1.1.3, the JPC may vote to grant one or both of the Parties additional time for regional evaluations or approval of a proposed Interregional Project(s).

Approval of an Interregional Project(s) by each Party's Board of Directors is required for the Interregional Project to qualify for interregional cost allocation. If a proposed Interregional Project(s) and associated cost allocation is not approved by the Parties within six (6) months of the JPC vote or any JPC approved extension, the proposed Interregional Project is deemed rejected. A rejected Interregional Project may be reevaluated and recommended by the JPC as part of a future Coordinated System Plan study.

The JPC shall inform the IPSAC of the outcome of each Party's regional evaluation of a proposed Interregional Project(s) and its respective cost allocation.

Section 9.3.3.5.1 Coordinated System Planning Study Report

At the completion of the Coordinated System Plan study, the JPC shall produce a draft report documenting the Coordinated System Plan study, including the Transmission Issues evaluated, studies performed, solutions considered, and, if applicable, the recommended Interregional Projects with the associated interregional cost allocation. The JPC shall provide the draft Coordinated System Plan study report to the IPSAC for review. The report will provide explanation for why any transmission solutions studied in the CSP were not recommended as Interregional Projects. The IPSAC will provide feedback on a draft report and a recommendation on any proposed Interregional Project(s) to the JPC as determined by an IPSAC vote, in accordance with Section 9.1.2.3.

The JPC will update the Coordinated System Plan study report based on feedback received from stakeholders as well as the outcome of each Party's respective regional evaluations of any proposed Interregional Projects. The Coordinated System Plan report shall be posted on each Party's respective interregional coordination webpage.

In accordance with the procedures under which the Parties provide Interconnection Service, each Party will coordinate with the other to conduct any studies required in determining the impact of a request for generator or merchant transmission interconnection and will engage in certain other activities provided under this Section 9.4. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. For the purposes of Section 9.4 and related subsections, "DP1" shall mean Decision Point I in regard to the MISO OATT and Decision Point One in regard to the SPP OATT and "DP2" shall mean Decision Point II in regard to the MISO OATT and Decision Point Two in regard to the SPP OATT. The term "cluster" shall mean: a group of interconnection requests in a study cycle being studied on a common timeline, and which will proceed into DP1 at the same time. The process for coordination of Interconnection Studies and Network Upgrades will include the following procedures set forth in Sections 9.4.1, 9.4.2 and 9.4.3.

The rules contained in this section shall apply to all clusters, interconnection customers, and interconnection requests regardless of whether such clusters, interconnection customers, or interconnection requests are included in the Joint Targeted Interconnection Queue ("JTIQ") Screening Group:

(a) Consistent with the data exchange provisions of this Agreement, the Parties will exchange modeling data as necessary for the study and coordination of interconnection requests. This will include associated updates to modeling data as necessary to reflect the other Party's relevant queue requests, contingency elements, monitored elements, planned upgrades, and other data as may be required.

(b) The identification of all impacts on the Parties' transmission systems shall include a description of the required Network Upgrade(s), and corresponding planning level cost estimates and construction schedule estimates.

(c) Construction of any Network Upgrades on the Affected System will be subject to the terms of the impacted Party's OATT and agreement among owners of transmission facilities subject to the control of the impacted Party and will be consistent with applicable federal, state or provincial regulatory policy.

(d) In the event that Network Upgrades are required on the potentially impacted Party's system, then such Network Upgrades shall be documented as a condition for full Interconnection Service in the interconnection agreement executed by the direct connect system. Additionally, the Parties will mutually agree on milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(e) Each Party will maintain a separate interconnection queue. The Parties will maintain a listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of the other Party. This information will be publicly posted on the Parties' respective websites.

The rules and procedures contained in this Section 9.4.2 shall apply to interconnection customers with interconnection requests that have been designated for inclusion in a JTIQ Participation Group and/or for the Expanded Scope Analysis identified in Section 9.4.2.d.iv.a. To the extent any provision in Section 9.4 and related subsections conflicts with the provisions pursuant to this Section 9.4.2 as applicable to JTIQ Upgrades, the provisions pursuant to this Section 9.4.2 shall govern for JTIQ Upgrades.

(a) Adoption of JTIQ Portfolio: The Parties may from time to time identify a JTIQ Portfolio to be constructed in one or both of the Parties' transmission systems that the Parties have determined will more efficiently and reliably facilitate the interconnection of one or more clusters of interconnection requests in both Parties' queues.

(i) The Parties shall coordinate in the identification and study of potential JTIQ Upgrades for inclusion in JTIQ Portfolios. Such coordination shall include, at a minimum: (i) meetings to be held periodically between representatives of each Party for the purposes of considering potential JTIQ Upgrades for inclusion in a JTIQ Portfolio and, as appropriate, enhancements to JTIQ processes; (ii) the exchange of study data relating to potential JTIQ Upgrades for inclusion in a JTIQ Portfolio; and (iii) if applicable, the presentation of study results to both Parties' stakeholders.

(ii) Each Party shall, after consultation with the other Party, present the same JTIQ Portfolio to its Board of Directors for approval in its respective regional transmission plan.

(b) Cost allocation for JTIQ Portfolios:

(i) Capital costs (i.e., engineering and construction costs, and applicable carrying costs and income tax impacts)

a) If any of the JTIQ Upgrades in a JTIQ Portfolio have been selected by December 31, 2023 to receive funds through the United States Department of Energy Grid Resilience and Innovation Partnerships Program (GRIP Program), any capital costs of the JTIQ Upgrades not funded through the GRIP Program shall be the amount which the JTIQ Generator Charge is designed to recover from the interconnection customers included in the JTIQ Commitment Group(s) for the applicable JTIQ Portfolio.

b) If none of the JTIQ Upgrades in a JTIQ Portfolio have been selected to receive funds through the GRIP Program, the Parties shall propose an appropriate cost allocation method for acceptance by the Commission prior to presenting the JTIQ

Portfolio to their respective Boards of Directors for approval.

(ii) Non-capital costs (i.e., operation and maintenance costs, administrative and general expenses, general and intangible plant depreciation and amortization, taxes other than income taxes, and other costs not included in capital costs):

a) One hundred percent (100%) of the annual non-capital costs allocable to JTIQ Upgrades shall be recovered consistent with each Party's regional OATT.

(c) Responsibility to Construct: Each Party shall assign to the applicable Transmission Owner(s) and maintain through its OATT, organizational documents, or other appropriate agreements, an obligation by the applicable Transmission Owner(s) to develop, construct, operate, and maintain JTIQ Upgrades.

(d) Identification of JTIQ Screening Group, JTIQ Participation Group and JTIQ Commitment Group:

(i) The JTIQ Screening Group shall consist of all interconnection customers who have submitted interconnection requests into a MISO DPP study cluster or SPP DISIS study cluster that: (1) has an application deadline that is after the date that the Parties' respective Boards of Directors have approved a JTIQ Portfolio; and (2) has not commenced DPP Phase I or DISIS Phase One studies pursuant to each party's OATT as of the date that the Parties have declared the JTIQ Portfolio fully subscribed.

(ii) The JTIQ Participation Group shall consist of all interconnection requests included in the JTIQ Screening Groups that meet the following criteria:

a) the interconnection request is determined to have an impact greater than five percent (5%) distribution factor (OTDF or PTDF[1]) on one or more facilities of the potentially impacted Party's transmission system modelled with all transmission facilities rated 100 kV and above; and

b) the interconnection request is determined to have greater than 1.00 MW (positive) impact on at least one JTIQ Upgrade included in the JTIQ Portfolio.

1 Power Transfer Distribution Factor (PTDF) - The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.
Outage Transfer Distribution Factor (OTDF) - The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

(iii) Each JTIQ Commitment Group shall include interconnection customers that have an interconnection request in a JTIQ Participation Group that has obtained an effective service agreement that obligates such interconnection customer to pay, and provide security for, the JTIQ Generator Charges within the twelve (12) month period ending April 30th of each year. The Parties shall provide in their regional OATTs that interconnection customers included in a JTIQ Commitment Group shall, upon the effective date of the applicable generator interconnection agreement, be responsible for the full amount of their share of the relevant JTIQ Portfolio, the charges for which shall be determined and issued pursuant to the provisions of the regional OATT and agreements applicable to each interconnection customer.

(iv) Interconnection requests included in the JTIQ Screening Group shall not be included in any Affected System study performed by the potentially impacted Party pursuant to Section 9.4.3 except as set forth in Sections 9.4.2.e.ii, 9.4.2.e.iii.a.ii.d, 9.4.2.d.iv.a.i and 9.4.2.d.iv.a.ii, below.

a) Notwithstanding the foregoing and subject to the exceptions set forth in Sections 9.4.2.d.iv.a.i and 9.4.2.d.iv.a.ii, each Party shall conduct for each interconnection request for which it is the direct connect Party, an analysis of the potential impacts of such interconnection request on the Affected System that are i) located within five (5) substations for facilities with a nominal operating voltage under 200kV, two (2) substations for facilities with a nominal operating voltage between 200 and 300 kV, and one (1) substation for facilities with a nominal operating voltage greater than 300 kV, from one of the direct connect Party's substations; and ii) have greater than or equal to ten percent (10%) distribution factor (OTDF or PTDF) on one or more facilities of the potentially impacted Party's transmission system. This analysis shall be referred to as the Expanded Scope Analysis. Each Party shall, through appropriate provisions in their respective OATTs, require interconnection requests that are determined to have impacts on the Affected System greater than the specified criteria pursuant to this paragraph to enter into an appropriate agreement with the Affected System to address such impacts in accordance with the rules of the Affected System.

i. Interconnection requests for generation located in MISO will be subject to the Expanded Scope Analysis if they (i) are included in the JTIQ Participation Group, or (ii) do not meet the criteria for inclusion in the JTIQ Participation Group and are not located in the MISO South Region. Interconnection requests for generation located in the MISO South Region, as described in MISO's Generator Interconnection Business Practices Manual, that do not meet the criteria for inclusion in the JTIQ Participation Group will proceed through the SPP Affected System process under Section 9.4.3.

ii. Interconnection requests for generation located in SPP will be subject to the Expanded Scope Analysis if they: (i) are included in the JTIQ Participation Group, or (ii) do not meet the criteria for inclusion in the JTIQ Participation Group and are not located in SPP Group 4 or 5, as described in the SPP Generator Interconnection Manual. Interconnection requests for generation located in SPP Group 4 or 5 that do not meet the criteria for inclusion in the JTIQ Participation Group will proceed through the MISO Affected System process under Section 9.4.3.

iii. For each DPP or DISIS study cluster commenced after the approval of the applicable JTIQ Portfolio and until such time as such JTIQ Portfolio is determined to be fully subscribed by the Parties, each Party shall monitor its own interconnection queue. Within ten (10) business days after a Party commences DPP Phase I or DISIS Phase One studies for a study cluster, such Party shall communicate to the other Party the number of MW of interconnection requests included in such cluster that have met the distribution factor and impact thresholds for inclusion in the JTIQ Participation Group. Within ten (10) business days of execution, or Commission approval if filed unexecuted, of the last generator interconnection agreement in a Party's study cluster commenced after the approval of the JTIQ Portfolio becomes effective and until such time as the JTIQ Portfolio is determined to be fully subscribed, the direct-connect Party shall report to the potentially impacted Party the total number of generator interconnection projects and MW of interconnection requests that have joined a JTIQ Commitment Group.

(e) Closing Subscription to the JTIQ Portfolio; Addressing Oversubscription and Undersubscription

(i) The Parties shall determine the Target MW Value and the resulting Threshold MW Value at the time the JTIQ Portfolio is identified by the Parties. The Target MW Value shall be the projected new interconnection MW enabled by the JTIQ Portfolio. The Threshold MW Value shall be eighty-five percent (85%) of the Target MW Value.

(ii) Prior to DP1 in each study cluster, the Parties shall develop a projection of the number of MW expected to commit to the JTIQ Portfolio from all study clusters that already have passed DP1 ("Commitment Projection"). The Commitment Projection shall include all JTIQ Commitment Groups to date for the applicable JTIQ Portfolio and an estimate of probable additional MW commitments to the JTIQ Portfolio from study cluster(s) that have passed DP1 for which all interconnection requests have not either received effective generator interconnection agreements or been withdrawn. In developing the Commitment Projection, the Parties shall apply methodologies that mitigate the risk of under-subscription.

a) If the Parties determine that the Commitment Projection exceeds the Threshold MW Value of the JTIQ Portfolio, the Parties shall declare the JTIQ Portfolio to be fully subscribed. Interconnection requests in any study cluster that has not passed DP1 shall be processed as set forth in Section 9.4.3 unless a subsequent JTIQ Portfolio is approved by the Parties' Boards before such study cluster commences.

b) If the Parties determine that the Commitment Projection does not exceed the Threshold MW Value of the JTIQ Portfolio, the Parties shall maintain the JTIQ Portfolio as open for one or more subsequent study cycles.

(iii) If the JTIQ Portfolio is not deemed fully subscribed pursuant to Section 9.4.e.ii, the Parties shall develop a projection of the number of MW that may commit to the JTIQ Portfolio from all study clusters to date, including the current study cluster(s) ("Potential MW Total"). The Potential MW Total shall be based on all JTIQ Commitment Groups to date for the applicable JTIQ Portfolio and probable additional MW commitments to the JTIQ Portfolio from recent study cluster(s), including the current study cluster(s). In order to assess probable additional MW commitments, the Parties can utilize information such as withdrawal trends among interconnection requests during recent study cycles of the Parties' interconnection queues.

a) If the Potential MW Total does not exceed the Target MW Value, then the current study cluster shall be processed in accordance with Sections 9.4.2(b)-(d), (f) and (g) in the same fashion as previous clusters included in the JTIQ Screening Group for such JTIQ Portfolio. If the Potential MW Total exceeds the Target MW Value, the current study cluster shall be processed in accordance with the following rules:

i. Step 1: Prior to DP2 of the current study cluster, the Affected System Party shall perform and provide results of an Affected System analysis, as set forth in Section 9.4.3, on the interconnection requests in the current study cluster to determine whether Network Upgrades in addition to those included in the JTIQ Portfolio or identified through the Expanded Scope Analysis are required to address the impact of interconnection requests in the current study cluster using reasonable efforts to expedite such study processes. Such additional Network Upgrades shall be referred to as Supplemental Affected System Upgrades. The costs of such studies shall be recovered from the interconnection customers with impacts on the Affected System as set forth in Section 9.4.3.

(a) If the analysis identifies no Supplemental Affected System Upgrades, the Parties shall deem the current study cluster to be fully enabled by the JTIQ Portfolio.

(b) If the analysis identifies Supplemental Affected System Upgrades, the Affected System Party shall proceed to Step 2.

ii. Step 2: If the Parties identify interconnection requests in the current study cluster that cause the need for one or more additional Network Upgrades due to impacts on the Affected System Party's transmission system:

(a) The Parties shall calculate the Threshold Charge for the JTIQ Portfolio. Such Threshold Charge shall be calculated using an estimate of plant in service value for the JTIQ Portfolio, excluding any amounts funded under the GRIP Program, based on the last estimate performed by the Parties prior to commencement of the current study cluster, divided by the Threshold MW Value.

(b) If the total per MW cost of an interconnection customer's Supplemental Affected System Upgrades, excluding costs identified through the Expanded Scope Analysis, does not exceed fifteen percent (15%) of the Threshold Charge, such interconnection request shall be deemed enabled by the JTIQ Portfolio and shall be responsible for the JTIQ Generator Charge and any costs identified through the Expanded Scope Analysis as well as any costs associated with the Supplemental Affected System Upgrades identified; or

(c) If the total per MW cost of such Supplemental Affected System Upgrades, excluding costs identified through the Expanded Scope Analysis, exceeds fifteen percent (15%) of the Threshold Charge, such interconnection customers shall be deemed not to have been enabled by the JTIQ Portfolio and shall not be required to pay the JTIQ Generator Charge. Such interconnection customers shall pay affected system costs for the Supplemental Affected System Upgrades identified as well as any costs identified through the Expanded Scope Analysis.

(d) If two hundred forty (240) months have passed since the first in-service date of a JTIQ Upgrade in this JTIQ Portfolio and this JTIQ Portfolio is not yet fully subscribed based on actual commitments prior to DP1 in the current study cluster(s), the current study cluster(s) and all subsequent study clusters shall be closed to subscription for this JTIQ Portfolio. Interconnection requests in any study cluster that has not passed DP1 when the above two conditions pertain shall be processed as set forth in Section 9.4.3, unless a new JTIQ Portfolio is approved before such study cluster commences and applies to such cluster.

(e) Updating Cost Estimates: The Parties shall coordinate with the Transmission Owners designated to construct the individual JTIQ Upgrades comprising the JTIQ Portfolio and shall provide estimated cost updates at least once annually beginning in the second year after a JTIQ Portfolio has been approved by both Boards of Directors and each year thereafter until all JTIQ

Upgrades in the JTIQ Portfolio have been placed into service. The Parties shall use the most updated estimates available as of the application date of a given study cluster to inform their calculation of any milestones to be collected from the JTIQ Participation Group customers during the MISO DPP or SPP DISIS cluster.

(f) Cost Recovery from the JTIQ Commitment Group and Backstop Funding

(i) JTIQ Generator Charge: The capital costs of each JTIQ Upgrade in the JTIQ Portfolio not otherwise funded through the GRIP Program will be recovered from the interconnection customers in the JTIQ Commitment Groups through a project-specific charge that will individually and collectively be referred to as the JTIQ Generator Charge. The references in Section 9.4.2.f and related subsections address the recovery from interconnection customers of the costs remaining after application of GRIP Program funds.

a) Each interconnection customer in a JTIQ Commitment Group will pay its share of each JTIQ Upgrade included in the JTIQ Portfolio based on the interconnection customer's MW of interconnection service as a percentage of the Threshold MW Value or, if larger, the final total subscribed amount of all Commitment Groups ("Final Commitment MW Total").

b) The costs of each JTIQ Upgrade in the JTIQ Portfolio will be recovered over a maximum of a 240-month period starting from each JTIQ Upgrade's recovery start date.

c) The JTIQ Generator Charge shall be calculated and assessed consistent with each Party's OATT.

i. The costs of JTIQ Upgrades in the JTIQ Portfolio shall be recoverable as those JTIQ Upgrades go into service.

ii. The interconnection customer's annual obligation for each JTIQ Upgrade will be calculated separately based on each JTIQ Commitment Group's start date for each JTIQ Upgrade's JTIQ Generator Charge.

iii. The applicable portion of the JTIQ ATRR for each JTIQ Upgrade in the JTIQ Portfolio will be collected monthly from each interconnection customer having a JTIQ Generator Charge obligation, as described in Section 9.4.2.f.i.a.

(ii) Backstop funding

a) In the event that the JTIQ Portfolio is not fully subscribed as set forth in Section 9.4.2.e.ii, or the interconnection customers ultimately responsible for JTIQ ATRR in the JTIQ Portfolio do not have effective generator interconnection agreements and service agreements obligating such interconnection customer to pay and provide security for the Generator Charge by the time a JTIQ Upgrade in the JTIQ Portfolio goes into service, the JTIQ ATRR(s) associated with those unsubscribed interconnection customers' obligations and/or unexecuted agreements shall be recovered from the constructing region consistent with that Party's OATT.

b) Funds received through the JTIQ Generator Charge, as a result of recovering the previous insufficiency of revenue from interconnection customers relative to the JTIQ ATRR, will be distributed within the Party's region where that JTIQ Upgrade is located consistent with that Party's regional OATT.

(iii) The Parties shall ensure that any non-jurisdictional Transmission Owner of a JTIQ Upgrade will be required to refund any amounts recovered in excess of the JTIQ ATRR for a JTIQ Upgrade.

(iv) JTIQ ATRR Update:

Transmission Owner shall update its JTIQ ATRR on a timely basis consistent with the applicable Party's OATT to reflect changes in elements of the formula rate template, including cost updates, for its JTIQ Upgrade. Each Party shall update the charges consistent with its regional OATT.

(g) Calculation, Collection and Distribution of JTIQ Generator Charge

Each Party shall through its OATT and/or *pro forma* agreements require that interconnection customers in its region included in a JTIQ Commitment Group must execute the other Party's service agreement obligating the interconnection customer to pay and provide security for the JTIQ Generator Charge to enable each Party to directly bill each interconnection customer in a JTIQ Commitment Group for the interconnection customer's share of the JTIQ Upgrades constructed in its region, regardless of which region the interconnection customer is connected to.

Each month each Party shall, in accordance with the terms of its OATT and *pro forma* agreements:

(i) determine and invoice the amounts due from the interconnection customers in the JTIQ Commitment Groups for the JTIQ Upgrades constructed in its region; and

(ii) distribute the revenue that it collects from interconnection customers pursuant to its OATT.

Each Party shall through its OATT or *pro forma* agreements provide that if the interconnection customer defaults in performance of the payment obligations required pursuant to that Party's OATT or *pro forma* agreement, that default shall be deemed to be a default of the payment obligations to the other Party, regardless of whether the interconnection customer has made timely payments to the other Party.

(h) Security requirements

Each Party shall establish in its respective OATT and/or *pro forma* agreements rules and procedures for requiring, obtaining, and maintaining security from interconnection customers in the JTIQ Commitment Groups for the JTIQ Upgrades constructed and owned by such Party's Transmission Owners.

Each Party shall through its OATT or *pro forma* agreements obligate the interconnection customers located in the Party's region to execute the other Party's service agreement obligating such interconnection customer to pay the JTIQ Generator Charge and to adhere to the other Party's rules and procedures for requiring, obtaining and maintaining security from interconnection customers associated with the portion of the JTIQ Portfolio to be constructed and owned by that Party's Transmission Owners.

The Parties shall coordinate with respect to the administration of applicable JTIQ security requirements, and at either Party's request, may provide information regarding security held, payment and default information from interconnection customers in the JTIQ Commitment Groups, and related information as appropriate.

(i) Exchange of Information between MISO & SPP

In addition to the express data sharing provisions identified throughout this Agreement, the Parties agree to coordinate on the exchange of information including, but not limited to, information regarding funds collected and disbursed in relation to the JTIQ Upgrades to enable each Party and the constructing Transmission Owners in each Party's region to sufficiently track cost recovery for the JTIQ Upgrades.

9.4.3 Coordination Procedure for Interconnection Requests Not Included in a JTIQ Participation Group or Expanded Scope Study

The rules and procedures contained in this section shall apply to the analysis of interconnection requests that have not been designated for inclusion in either a JTIQ Participation Group or an Expanded Scope Study.

(a) The relative queue position for interconnection requests in the MISO or SPP interconnection queues will be determined by the date on which DP1 closes for the respective cluster. The interconnection requests included in the study cluster having the earlier deadline will have higher queue priority. For all study request clusters prior to the MISO DPP 2020 cycle and SPP DISIS-2018-001 cluster, the following deadlines for each Party will be used to establish the queue priority rather than DP1 deadlines:

(i) The MISO M2 milestone payment submission deadline per the MISO OATT.

(ii) The SPP deadline to submit a request into the Definitive Interconnection System Impact Study (DISIS) per the SPP OATT.

Interconnection requests in MISO and SPP will not be considered to have equal queue priority. In the event that the deadlines of each RTO's DP1 fall on the same date, queue priority for such interconnection requests shall be established based on each RTO's respective anticipated start date for DP2 calculated as of the close of DP1, with the earlier start date having higher queue priority.

(b) Studies to be performed to determine the impacts of the proposed interconnection on the potentially impacted Party will be conducted as follows:

(i) The transmission reinforcement and study criteria used in the potentially impacted Party's System Impact Studies will conform to and incorporate the provisions contained in the Parties' respective business practices and the OATTs.

(ii) The SPP and SPP Transmission Owner study procedures, planning criteria, and cost allocation provisions will apply to the studies performed to determine the impacts on the SPP transmission system when SPP evaluates the impact on SPP transmission facilities of MISO interconnection requests. SPP's modeling criteria applicable to Network Resource Interconnection Service (NRIS) requests in SPP will also apply to MISO requests seeking NRIS in MISO for the amount of NRIS being requested in MISO. SPP's modeling criteria applicable to Energy Resource Interconnection Service (ERIS) requests in SPP will also apply to MISO requests seeking ERIS in MISO for the amount of ERIS being requested in MISO. Modeling details that SPP will use when SPP is the Affected System can be found in Section 19 of the Guidelines for Generator Interconnection Requests.

(iii) The MISO and MISO Transmission Owner study requirements, planning criteria, and cost allocation requirements will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact on MISO transmission facilities of SPP interconnection requests. During the course of MISO's Affected System Interconnection Study, MISO shall apply ERIS criteria to all of SPP's Interconnection Request(s). Detailed information about the modeling process and assumptions used by MISO for such analysis when MISO is the Affected System are located in MISO's Generator Interconnection Business Practices Manual, BPM-015 at section 6.

(iv) If a Party identifies a criteria violation on a tie line path interconnecting the SPP and MISO transmission systems and the limiting element(s) on such tie line path is not under the control or ownership of the Party that identified the criteria violation, then the limiting element(s) for the tie line path will be required to be upgraded such that it is no longer a limiting element. Such upgrade shall be processed in accordance with the business practices and OATT of the Party that owns or controls the limiting element(s).

(v) During the course of Affected System studies, each Party will sink the output of the other Party's interconnection requests in the same area or subregion, if applicable, as the host RTO.

(vi) If the Parties cannot mutually agree on the nature of the studies to be performed, they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(c) The direct connect Party shall identify potential impacts on the Affected System when conducting its own System Impact Study of new Interconnection Requests. Potential impacts on the Affected System shall be communicated to the potentially impacted Party by the direct connect Party. The potentially impacted Party shall, in accordance with applicable procedures, guidelines, criteria, and standards, make the final determination of whether its system is impacted by requests on the direct connect system and identify the Network Upgrades necessary to mitigate such impacts. The direct connect Party will be responsible for communicating the results of the potentially impacted Party's analysis to the direct connect Party's interconnection customers. If a Party identifies potential impacts on its system as a result of an interconnection request by the other Party's interconnection customer(s), such potentially impacted Party shall provide any supporting models or analysis to the applicable interconnection customer upon request, subject to the same requirements and limitations applicable to that Party's own interconnection customer.

(d) During the course of its DISIS, SPP shall monitor all facilities with nominal voltage 100 kV and higher of those MISO Transmission Owners that are immediately adjacent to SPP facilities ("First Tier Area"). Thermal loading of facilities within First Tier Areas that exceed the normal rating during system-intact conditions or that exceed the emergency rating during contingency conditions shall be identified. Voltages of facilities within First Tier Areas that are outside the range of 0.95 to 1.05 per unit during system-intact conditions or 0.90 to 1.05 per unit during contingency conditions shall be identified. SPP shall provide to MISO the results of the potential impacts to the MISO transmission system. These potential impacts may be included in the SPP DISIS report along with any information regarding the validity of these impacts and any transmission system reinforcements received from MISO and the MISO Transmission Owners.

(i) No later than 5 Business days after the commencement of Phase One and Phase Two of the SPP DISIS, the Interconnection Facilities Study, or any restudy, SPP shall forward to MISO the information necessary for MISO and the MISO Transmission Owners to study the impact of the SPP interconnection request(s) on the MISO transmission system. MISO and the MISO Transmission Owners shall study the impact(s) of the SPP interconnection request(s) on the MISO transmission system and provide the results to SPP by the later of (1) 30 days following study commencement or (2) 15 days prior to the scheduled completion of Phase Two of the SPP DISIS, the Interconnection Facilities Study, or any restudy, as applicable.

(ii) During the determination of reinforcements for an interconnection request that are required to mitigate MISO constraint(s), SPP and MISO may identify other planned reinforcement(s) that may alleviate such constraint(s) inside the MISO region. Under such circumstances, any SPP interconnection project relying on those reinforcement(s) shall have limited operation service until those reinforcement(s) are placed into service. MISO may perform interim studies to determine the necessary limitation on Interconnection Service associated with the SPP interconnection request until the necessary upgrades identified through MISO's Affected System analysis are in service.

(e) During the course of its Definitive Planning Phase (DPP) studies, MISO shall monitor the SPP transmission system and provide to SPP the results of the potential impacts to the SPP transmission system. This monitoring will include an examination of the potential projects to impact the SPP system through determination if the project under study has ≥ three percent (3%) distribution factor or ≥ 5MW impact or ≥ one percent (1%) of facility rating on any SPP facilities under normal and contingency conditions. These potential impacts may be included in the MISO DPP report along with any information regarding the validity of these impacts and any transmission system reinforcements received from SPP and the SPP Transmission Owners.

(i) No later than 5 Business Days after the commencement of the MISO DPP Phase I study, MISO shall forward to SPP the information necessary for SPP and the SPP Transmission Owners to study the impact of the MISO interconnection request(s) on the SPP transmission system. SPP and the SPP Transmission Owners may begin studying the impact of the MISO interconnection request(s) on the SPP transmission system.

(ii) No later than 5 Business Days after the commencement of the MISO DPP Phase II study, MISO shall forward to SPP the information necessary for SPP and the SPP Transmission Owners to study the impact of the MISO interconnection request(s) on the SPP transmission system. SPP and the SPP Transmission Owners shall study the impact(s) of the MISO interconnection request(s) on the SPP transmission system and provide the results to MISO within 30 days following the commencement of DPP Phase II.

(iii) No later than 5 Business Days after the commencement of the MISO DPP Phase III study or any restudy, MISO shall forward to SPP the information necessary for SPP and the SPP Transmission Owners to study the impact of the MISO interconnection request(s) on the SPP transmission system. SPP and the SPP Transmission Owners shall study the impact(s) of the MISO interconnection request(s) on the SPP transmission system and provide the results to MISO within 30 days following the commencement of DPP Phase III or any restudy, as applicable.

(iv) During the determination of reinforcements for an interconnection request that are required to mitigate SPP constraint(s), SPP and MISO may identify other planned reinforcement(s) that may alleviate such constraints inside the SPP region. Under such circumstances, any MISO interconnection project relying on those reinforcement(s) shall have conditional Interconnection Service until those reinforcement(s) are placed into service. SPP may perform interim studies to determine the necessary limitation on Interconnection Service associated with the MISO interconnection request until the necessary upgrades identified through SPP's Affected System analysis are in service.

(f) The impacted Party whose transmission system requires mitigation of constraint(s) identified in an impacted Party's System Impact Study shall tender to and enter into a Facilities Study agreement with the interconnection customer as required under the impacted Party's OATT.

(g) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of any Affected System Study (Affected System Impact Study and Affected System Facility Study) and forward collected amounts to the potentially impacted Party.

(h) If the results of the Affected System's System Impact Study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the System Impact Study prepared for the interconnection customer.

(i) For any interconnection request that had previously been identified as potentially impacting the system of the other Party, the direct connect Party will ensure that all coordination under this Section 9.4 has been completed and that any required Network Upgrades identified by the potentially impacted Party are included in the applicable interconnection agreements prior to those agreements being executed.

(j) The Parties will strive to minimize the costs associated with the Coordinated study process.

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon either the posting to the OASIS of a request for service or the review of studies related to the evaluation of that service request, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party's OASIS is unnecessary (i.e., the potentially impacted Party is "off the path"), then that Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to maximize the cost efficiency of the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) During the System Impact Study, the potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the Party receiving the request. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request's Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the applicable Party's OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

When under Section 9.4, it is determined that a generation or merchant transmission interconnection to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties' Order No. 2003 compliance filings as accepted by the FERC.

Section 9.6.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.5, it is determined that the granting of a long-term firm delivery service request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

The Coordinated System Plan will identify Network Upgrades under the Coordinated System Plan as Interregional Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the project cost for each such project that is to be allocated to each Party on behalf of its transmission customers. The JPC will determine the interregional allocation of costs to be shared by the Parties' transmission customers for such Interregional Project(s) based on the procedures developed pursuant to this Section 9.6.3. Each Party will then determine regional allocation of the costs of the Interregional Project pursuant to its respective OATT. The proposed allocation of costs will be reviewed with the IPSAC.

A project that meets all of the following criteria shall be designated as an approved Interregional Project:

i. The project is evaluated as part of a Coordinated System Plan and recommended by the JPC, as described in Section 9.3.3;
ii. The project is approved by each Party's Board of Directors in their respective regional planning processes as outlined in their respective OATTs;
iii. The benefits to MISO and SPP must each represent 5% or greater of the total benefits identified for the combined MISO and SPP region in accordance with Section 9.6.3.1.1;
iv. The estimated in-service date is within 10 years from the date the project is approved by the respective Boards of Directors of MISO and SPP, and if approved on different dates, on the date of the latest approval; and
v. The project may interconnect to facilities in both the MISO and SPP regions or be wholly within the MISO or SPP region. The facilities to which the project is proposed to interconnect may be either existing facilities or transmission projects included in the regional transmission plan that are currently under development.

The Parties shall coordinate to evaluate the benefits to their respective regions individually, using the agreed upon benefit metric(s) over a multi-year analysis to determine whether a proposed project qualifies as an Interregional Project. The Parties shall perform this evaluation as follows:

a. Projects identified by the JPC as primarily addressing an economic issue(s):

   i. The Parties shall utilize a benefit metric to analyze the anticipated annual economic benefits of construction of a proposed Interregional Project to transmission customers of each Party. Benefits are measured for a project by the estimated change in the benefit metric with and without the incorporation of the proposed project. The benefit metric is based upon the impact of the project on adjusted production cost (APC), which is adjusted to account for purchases and sales. Each Party's adjusted production cost represents the summation of the adjusted production cost for the defined areas in each Party's region. Each area's production cost shall be adjusted for purchases and sales pursuant to each Party's respective regional process.

   ii. The benefit metric shall be calculated for each Party for each simulated year. Benefits for intermediate years between simulated years will be based on interpolation. Benefits for years beyond the last simulated year will be based on extrapolation. The total project benefit shall be determined by calculating the present value of annual benefits for the first 20 years of project life after the projected in-service date.

   iii. Economic projects may also provide reliability benefits. The reliability benefit is as defined in Section 9.6.3.1.1.b.i. If a proposed Interregional Project identified by the JPC as primarily addressing an economic issue also provides reliability benefits to either Party, the reliability benefit value, as that value is defined in the Parties' respective tariffs, will be added to the APC benefit value, including any negative APC benefit values.

   iv. Economic projects may also provide public policy benefits. The public policy benefit is as defined in Section 9.6.3.1.1.c.i. If a proposed Interregional Project identified by the JPC as primarily addressing an economic issue also provides public policy benefits to either Party, the public policy benefit value will be added to the APC benefit value, including any negative APC benefit value.

   v. Other benefit metrics may be added to the evaluation of the overall benefits of interregional projects in the CSP at a later date if those benefits metrics are agreed upon by both regions.

b. Projects identified by the JPC as primarily addressing a reliability issue(s):

   i. When an Interregional Project would replace a Party's regional project to address a reliability issue, the reliability benefit is the avoided cost of each Party's regional project(s) addressing the reliability issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.

ii. Because reliability projects may also provide APC benefits, the APC will be calculated pursuant to Section 9.6.3.1.1a. If the project identified by the JPC as primarily addressing a reliability issue also provides APC benefits to either Party, the APC benefit value will be added to the reliability benefit value, the reliability benefit value will be added to the APC benefit value, including any negative APC benefit values. In situations where both parties agree that the inclusion of negative APC values will result in an otherwise beneficial project not being approved, the Parties will work together to resolve this unintended consequence.

c. Projects identified by the JPC as primarily addressing public policy issue(s):

i. When an Interregional Project would replace a Party’s regional project to address a public policy issue, the public policy benefit is the avoided cost of each Party’s regional project(s) addressing the public policy issue(s). By agreement of the JPC, an Interregional Project shall be eligible to displace one or more regional projects in either SPP or MISO, as defined in their respective tariffs, if the Interregional Project is able to more efficiently or cost-effectively meet the identified need than the displaced project.

ii. Because public policy projects may also provide APC benefits, the APC will be calculated pursuant to Section 9.6.3.1.1a. If the proposed Interregional Project identified by the JPC as primarily addressing a public policy issue also provides APC benefits to either Party, the APC benefit value will be added to the public policy benefit value, including any negative APC benefit. In situations where both parties agree that the inclusion of negative APC values will result in an otherwise beneficial project not being approved, the Parties will work together to resolve this unintended consequence.

For Interregional Projects that meet all of the qualifications in Section 9.6.3.1, the applicable project costs shall be allocated to the respective Parties' transmission customers in proportion to the net present value of the total benefits calculated for each Party pursuant to each Party's respective regional provisions.

MISO will calculate the dollar value of the benefits of a proposed Interregional Project using its MTEP analysis (i.e., adjusted production costs and avoided reliability and public policy costs) and SPP will calculate the dollar value of the benefits using its ITP analysis (i.e., adjusted production costs and avoided reliability and public policy costs). Each Party will then determine whether the proposed Interregional Project satisfies its respective regional criteria and the criteria in Section 9.6.3.1 using each Party's pro rata share of the total cost as determined by its pro rata share of the total dollar value of benefits.

For example,

MISO Cost = ((MISO Benefit)/(MISO Benefit + SPP Benefit))*Total Cost;

SPP Cost = ((SPP Benefit)/(MISO Benefit + SPP Benefit))*Total Cost;

where MISO Benefit = Net Present Value of MISO's benefits as calculated in MISO's MTEP process, and SPP's Benefit = Net Present Value of SPP's benefits as calculated in SPP's ITP process.

The recovery of any share of cost of an Interregional Project allocated to either Party shall be recovered by each Party according to the applicable OATT provisions of the Party to which such cost recovery is allocated.

Each Party shall provide to the JPC for posting on each respective Party's interregional coordination webpage a quarterly status report on approved Interregional Projects, including at a minimum the current estimated project cost and in-service date.

To obtain Network Upgrades under this Article IX, SPP will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the SPP Membership Agreement and the SPP OATT, as both may be amended or restated from time to time, and MISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midcontinent Independent System Operator, Inc., A Delaware Non-Stock Corporation, MISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

For an Interregional Project approved for interregional cost allocation under Section 9.6.3 that is solely interconnected to transmission facilities under the control of one Party, that Party's OATT shall be used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project.

For all or part of an Interregional Project approved for interregional cost allocation under Section 9.6.3 that will interconnect to transmission facilities under the control of each Party, the applicable OATT used to designate the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable Interregional Project shall be determined based on the proportion of benefits as calculated pursuant to Section 9.6.3.1.1, unless jurisdictional limitations preclude a Party's Transmission Owner from constructing and/or owning transmission facilities in proportion to the benefits as calculated pursuant to Section 9.6.3.1.1.

When a tie-line interregional project interconnects with transmission facilities that are under the respective functional control of the neighboring RTOs ,and that are respectively owned by adjacent Transmission Owners in each RTO, the benefits calculation, pursuant to Section 9.6.3.1.1 of the JOA, would be used to determine the ownership shares of such Transmission Owners, which in turn would determine the tariff applicable to the portion respectively owned by the relevant MISO Transmission Owner and SPP Transmission Owner. Majority ownership does not determine the tariff that will govern the entire project or line. Instead, the portion of the project owned by a Transmission Owner will be governed by the RTO tariff governing that Transmission Owner. By way of exception, if there are jurisdictional limitations, the ownership for the Transmission Owner in each respective RTO will be determined in accordance with the identified jurisdictional boundaries. For example, if based on the benefits of the Interregional Project the ownership would be split 50/50 between the Parties but, due to the geographic location of the Interregional Project, only a Transmission Owner or qualified transmission developer from one Party is permitted to construct and own projects in that location, then that portion of the project would be 100% owned by the Transmission Owner or qualified transmission developer constructing the project. For Interregional Projects that are solely located within one Party's region, the designation of the Transmission Owner(s) or qualified transmission developer(s) responsible for constructing the project will be determined in accordance with the Party's tariff.

Parties agree to coordinate on the designation of the entity to construct, implement, own, operate, maintain, repair, restore, and finance the applicable portion of an Interregional Project that will interconnect to the transmission facilities under the control of each Party.

After approval of an Interregional Project, the Parties may negotiate the advancement of the in-service date of a project.

[Reserved for Future Use]

The Parties agree that each Party will leverage technology, where feasible, to perform electronic approvals of schedules and to perform electronic checkouts. The Parties agree to follow the following scheduling protocols:

Each Party, acting as the scheduling agent for their respective BAs, will conduct all checkouts with their first tier BAs or the scheduling agent acting on behalf of those first-tier BAs. A first tier BA is any BA that is directly connected to any Party’s members’ BA.

The Parties will require all schedules between the Parties, other than reserve sharing or other emergency events and loss payback schedules, to be tagged via the NERC tagging standard. For reserve sharing and other emergency schedules that are not tagged, the Parties will enter manual schedules after the fact into their respective scheduling systems to facilitate checkout between the Parties.

When there is a scheduling conflict, the Parties will work in unison to modify the schedule as soon as practical. If there is a scheduling conflict that is identified before the schedule has started, then both Parties will make the correction in real-time and not wait until the quarter hour. If the schedule has already started and one Party identifies an error, then the Parties will make the correction at the earliest quarter hour increment. If a scheduling conflict cannot be resolved between the Parties (but the source and sink have agreed to a MW value), then the Parties will both adjust their numbers to that same MW value. If source and sink are unable to agree to a MW value, then the previously tagged value will stand for both Parties.

For BAs or associated scheduling agents that do not use the respective Parties' electronic scheduling interfaces, the Parties will contact those entities by telephone to perform checkouts. When performing checkouts by telephone, each entity will verbally repeat the numerical NSI value to ensure accuracy.

The Parties will perform the following types of checkouts:

(a) Pre-schedule (day-ahead) daily between 1800 and 2200 hours(Eastern Prevailing Time);
- Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(b) Hourly Before the Fact (Real-Time);
- Checkout for the next hours shall be net scheduled. Import and export totals may also be verified in addition to NSI if it is deemed necessary by either Party. The Parties may checkout individual schedules if deemed necessary by either Party.
- Checkout for the top of the next hour is performed during the last half of the current hour.

(c) Daily after the fact checkout shall occur no later than ten (10) business days after the fact (via email or mutually agreed upon method).

(d) Monthly after the fact checkout shall occur no later than one (1) month after the fact (via phone or mutually agreed upon method).

The Parties will require that each of these checkouts be performed with first tier BAs. If a checkout discrepancy is discovered, the Parties will use the NERC tag to find where the discrepancy exists. The Parties will require any entity that conducts business within its RC Area to checkout with the Parties using NERC tag numbers; special naming convention used by that entity or other naming conventions given to schedules by other entities will not be permitted.

Section 11.1 Coordination Objectives

Each Party acknowledges that voltage control and reactive power coordination are essential to promote reliability. Therefore, the Parties establish the Voltage and Reactive Power Coordination Plan under this Article by which they shall conduct such coordination.

Section 11.1.1

The Voltage and Reactive Power Coordination Plan addresses the following components: (a) mechanisms to assist the Parties in maintaining a wide area view of interconnection conditions by enhancing the coordination of voltage and reactive levels throughout their RTO footprints; (b) reliability plans to ensure the maintenance of sufficient reactive reserves to respond to scenarios of high load periods, loss of critical reactive resources, and unusually high transfers; and (c) processes for sharing of data with other neighboring RCs for their analysis and coordinated operation.

Section 11.1.2

The Parties will review the Voltage and Reactive Power Coordination Plan in accordance with NERC standards to make revisions and enhancements as appropriate to accommodate additional capabilities or changes to industry reliability requirements.

Section 11.2 Voltage and Reactive Power Coordination Plan.

The Parties will utilize the following plan to coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on their respective systems.

Under normal conditions, each Party will coordinate with the Transmission Owners, TOPs, and BAs as necessary and feasible to supply its own reactive load and losses at all load levels.

Section 11.2.2

Voltage schedule coordination is the responsibility of each Party. Generally, the voltage schedule is determined based on conditions in the proximity of generating stations and EHV stations with voltage regulating capabilities. Each Party works with its respective Transmission Owners, Transmission Operators, Generator Owners, Generator Operators, and BAs (where appropriate) to determine adequate and reliable voltage schedules considering actual and post-contingency conditions.

Section 11.2.3

Each Party will establish voltage limits at critical locations within its own system and coordinate this information with the other Party as needed. This information shall include normal high voltage limits, normal low voltage limits, post-contingency emergency high voltage limits and post-contingency emergency low voltage limits, and, if available shall identify the voltage limit value at which load shedding will be implemented.

Section 11.2.4

Where the sufficient detail in EMS Model permits, each Party will maintain awareness of the voltage limits in the other Party's area and awareness of outages and potential contingencies that could result in violation of those voltage limits.

The Parties will clearly communicate the level of voltage support needed during pre- or post-contingency conditions requiring voltage and reactive power coordination.

Each Party shall maintain a list of actions that are available to be taken when voltage support is necessary to respond to anticipated or prevailing system conditions.

As part of seasonal preparations, the Parties will conduct meetings to discuss issues due to the anticipated conditions and determine any actions that may be required in response to voltage concerns. The Parties will provide the voltage schedule information on an annual basis to ensure that the information is current.

In concert with the coordination of Outages addressed in Article VII and the Parties' respective day-ahead reliability analysis processes, the Parties will coordinate the impact of outages and system conditions on the voltage/reactive profile. Coordination will include the following elements:

Each Party will review its forecasted loads, transfers, and all information on available generation and transmission reactive power sources at the beginning of each shift.

If no reactive problems are anticipated after the review, each Party will operate independently in accordance with the above stated criteria and any individual system guidelines for the supply of the Party’s reactive power requirements.

Section 11.2.8.3

If either Party anticipates reactive problems after the review, it may request joint implementation of reactive support levels under this Voltage and Reactive Power Coordination Plan, as it deems appropriate to the situation. When a Party calls for a particular level of support to be implemented under this Plan, it or the applicable TOP must identify the time it will start adjusting its system, the support level it is implementing, and the voltage problem area.

Section 11.2.8.4

If a Party experiences an actual low or high voltage condition after initial reactive support measures are taken, then the emergency reactive support level is implemented for the area experiencing the problem. The Party will also notify applicable RCs as soon as feasible. In addition, the Voltage and Reactive Power Coordination Plan is to be consulted to determine if further action is necessary to correct an undesirable voltage situation.

Section 11.2.9

The Parties will coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on the Parties' systems, and surrounding systems. The following actions are intended to ensure that bulk systems voltage levels enhance system reliability.

Section 11.2.9.1 Specific Voltage Schedule Coordination Actions.

(a) Each Party has oversight or operational or functional control of reactive sources within its system and will direct adjustments to voltage schedules at appropriate facilities.

(b) Each Party generally will coordinate the adjustment of voltage schedules to best utilize resources for operation prior to coordinated actions with the other Party.

(c) If a Party anticipates voltage or reactive problems, it will inform the other Party (operations planning with respect to future day and RC with respect to same day) of the situation, describe the conditions, and request voltage/reactive support under this Plan. As a part of the request, the Party must identify the specific area where voltage/reactive support is requested and provide an estimate of the magnitude and time duration of the request as well as the specific requirements for reactive support. The Parties will determine the appropriate measures to address the condition and develop a plan of action.

(d) Each Party will contact its affected Transmission Owners, TOPs, Generator Owners, Generator Operators, and BAs (where appropriate). The purpose of this call is to ensure that the situation is fully understood and that an effective operating plan to address the situation has been developed. If necessary the Parties will convene a conference call with the affected Transmission Owners, TOPs, and BAs.

(e) Each Party will coordinate voltage schedule changes requested by the other Party, provided that a Party may decline a requested change if the change would result in equipment violations or reduce the effective operation of its facilities. A Party that declines a requested change must inform the requesting Party that the request cannot be granted and state the reason for denial.

Section 11.2.10.1

Each Party will monitor power transfer on interfaces defined as a Flowgate used to control voltage collapse conditions. In cases where the potential for voltage collapse (or cascading) is identified, prompt voltage support and generation adjustments may be needed. Where coordinated effort is required for voltage stability interfaces, generation adjustment requests to avoid voltage collapse or cascading conditions must be clearly communicated and implemented promptly. Using these limits the Parties will implement the following real-time coordination:

(a) At 95% of Interface Limit

- A Party, which observes the reading shall call the other Party to discuss whether further analysis is required.
- The monitoring Party will notify other RCs via the RCIS.
- The Parties will contact the affected TOPs, Generator Operators, and BAs (where appropriate) to discuss reactive outputs and adjustments required.
- The applicable Party takes appropriate actions, which may include re-dispatching generation and directing schedule curtailments.

(b) Exceeding Interface Limit

- The Party owning the Flowgate will declare an emergency and inform other RCs of the emergency.
- The applicable Party will take immediate action, which may include generation redispatch, ordering immediate schedule curtailments, and, if required, load shedding.

Where feasible, and if both Parties' EMS models have sufficient detail, each Party will attempt to duplicate the other Party's power transfer evaluation in order to provide backup limit calculation in the event that the primary Party is unable to accurately determine the appropriate reliability limits.

Section 11.2.10.3

If a new power transfer interface is determined to exist and detailed modeling does not exist for the interface, the Parties will coordinate to determine how their models need to be enhanced and to determine plans for coordination in furtherance of the enhancement.

The Parties will use the Interregional Coordination Process, Attachment 2 to this Agreement, when, in the exercise of good utility practice, a Party determines that the redispatch of generation units on the other Party's transmission system would reduce or eliminate the need to resort to TLR or other transmission-related procedures, or would permit a more economical response to congestion than redispatch or other transmission-related procedures by the Party obligated to resolve the congestion.

(a) On a periodic basis determined by the Parties, the Parties shall identify potential transmission operating constraints that could result in the need to use TLR or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation on the other's system.

(b) In addition to the identification of such potential transmission operating constraints, the Parties shall each identify generation units on the other Party's system, the redispatch of which would alleviate the identified transmission constraints.

(c) From the identified transmission constraints, the Parties shall agree in writing on the transmission operating constraints redispatch options, and compensation for redispatch that shall be subject to this Section until otherwise agreed. In reaching such agreement, the Parties shall endeavor reasonably to limit the number of transmission constraints that are subject to this Section so as to minimize potential cost shifting among market participants of the Parties resulting from the redispatch of generation under this Section. Both Parties shall post the transmission operating constraints that are subject to this Section on their respective Internet sites.

If (i) a transmission constraint subject to this Section 12 occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) MISO or SPP, as applicable, has determined that it must either use TLR or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraints. Upon such request, MISO or SPP, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with good utility practice.

MISO will be the Native RC and the Native BA. MISO will be responsible for monitoring transmission related congestion (SOLs and IROLs) on its transmission system. SPP will be the Attaining RC and the Attaining BA. SPP will be responsible for the commitment and dispatch of the resources that are physically located within the MISO BAA and that are pseudo-tied into the SPP BAA. SPP will include the impacts of such pseudo-ties in its congestion management procedures.

SPP will be the Native RC and the Native BA. SPP will be responsible for monitoring transmission related congestion (SOLs and IROLs) on its transmission system. MISO will be the Attaining RC and the Attaining BA. MISO will be responsible for the commitment and dispatch of the resources that are physically located within the SPP BAA and that are pseudo-tied into the MISO BAA. MISO will include the impacts of such pseudo-ties in its congestion management procedures.

If only a portion of the installed capacity of a resource is pseudo-tied out of the Native BAA and into the Attaining BAA such that a unique share resides in each Balancing Authority Area, the Attaining BA will be responsible for sending commitment and dispatch instructions to that portion of the resource pseudo-tied into the Attaining BA. The Native BA will be responsible for sending commitment and dispatch instructions to the portion of the resource that remains in the Native BA.

The sum of the shares residing separately in the respective BAA shall not exceed the nameplate capability of the entire resource. The individual portions of the resource shall not exceed the modeled capacity in their respective BAA.

SPP and MISO agree that each Party’s respective OATT outlines the transmission service requirements related to the delivery of energy from pseudo-tied resources or the delivery of energy to pseudo-tied load.

SPP and MISO agree that the entity pseudo-tying the resource from the Native BAA to the Attaining BAA will obtain station service for the pseudo-tied resource in accordance with the rules of the Native BA.

SPP and MISO agree that the pseudo-tied resource is non-recallable by the Native RC and Native BA.

SPP and MISO agree that in the event either Party declares a system emergency with respect to its system, the Parties will coordinate in accordance with Section 8.1 of this Agreement.

SPP and MISO agree that each Party's respective OATT outlines the requirements for losses related to the delivery of energy from pseudo-tied resources or the delivery of energy to pseudo-tied load.

SPP and MISO agree that in the event communication is lost between any of the Parties (including communication between the Native BA or the Attaining BA and the pseudo-tie), the Native BA and the Attaining BA will freeze at the last known output value and it is the responsibility of the pseudo-tie to verbally communicate changes of the real time pseudo-tie output values with the other Parties.

SPP and MISO shall each have the right to suspend a pseudo-tie between their respective BAs in accordance with their respective OATT. SPP and MISO shall coordinate the change to the status of the pseudo-tie.

SPP and MISO shall each have the right to terminate a pseudo-tie between their respective BAs in accordance with their respective OATT and the notice provisions below. SPP and MISO shall coordinate the change to the status of the pseudo-tie.

The BA seeking to suspend or terminate the pseudo-tie in accordance with their respective OATT shall give the other BA at least sixty days (60) days written notice prior to the effective date of such termination, subject to receiving all necessary regulatory approvals.

SPP and MISO agree that the coordination concerning overlapping congestion on a pseudo-tied load or resource asset (as defined in FERC's orders in Docket Nos. EL17-89 and EL19-60) shall be addressed in accordance with Section 3.4 of the ICP, Real-Time Energy Market Coordination Procedures for Overlapping Congestion.

The Parties agree to file this Agreement jointly with FERC on or before December 1, 2004 and to cooperate with each other as necessary and appropriate to facilitate such filing. In that filing, the Parties shall request FERC to approve an effective date of December 1, 2004 (“Effective Date” is the date specified by the FERC).

The SACC established under the Memorandum of Understanding, shall perform the following with respect to this Agreement:

(a) Meet no less than once annually to determine whether changes to this Agreement would enhance reliability, efficiency, or economy and to address other matters concerning this Agreement as either Party may raise.

(b) Conduct additional meetings upon Notice given by either Party, provided that the Notice specifies the reason for the requested meeting.

(c) Establish task forces and working committees as appropriate to address any issues a Party may raise in furtherance of the objectives of this Agreement.

(d) Conduct dispute resolution in accordance with this Article.

(e) Initiate process reviews at the request of either Party for activities undertaken in the performance of this Agreement.

The SACC shall have the authority to make decisions on issues that arise during the performance of the Agreement based upon consensus of the Parties' representatives thereto.

The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede either Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from either Party's performance of, or failure to perform, this Agreement and which the Parties are unable to resolve prior to invocation of these procedures.

In the event a dispute arises, a Party shall give written notice of the dispute to the other Party. Within ten (10) days of such Notice, the SACC shall meet and the Parties will attempt to resolve the Dispute by reasonable efforts through good faith discussion and negotiation. Each Party shall also be permitted to bring no more than two (2) other individuals to Executive Committee meetings as subject matter experts; however, all representatives must be employees of the Party they represent. In addition, if the Parties agree that legal representation would be useful in connection with a meeting, each Party may bring two (2) attorneys (who need not be employees of the Party they represent). In the event the SACC is unable to resolve within twenty (20) days of such Notice, either Party shall be entitled to invoke Step 2.

A Party may invoke Step 2 by giving Notice thereof to the SACC. In the event a Party invokes Step 2, the SACC shall, in writing, and no later than five (5) days after the Notice, refer the dispute in writing to the Parties' Presidents for consideration. The Parties' Presidents shall meet in person no later than fourteen (14) days after such referral and shall make a good faith effort to resolve the dispute. The Parties shall serve upon each other, written position papers concerning the dispute, no later than forty-eight (48) hours in advance of such meeting. In the event the Parties' Presidents fail to resolve the dispute, either Party shall be entitled to invoke Step Three.

Upon the demand of either Party, the dispute shall be referred to FERC's Office of Dispute Resolution for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

In the event of disputes involving Confidential Information, infringement or ownership of Intellectual Property or rights pertaining thereto, or any dispute where a Party seeks temporary or preliminary injunctive relief to avoid alleged immediate and irreparable harm, the procedures stated in Section 14.2 and its subparts shall apply but shall not preclude a Party from seeking such temporary or preliminary injunctive relief, provided, that if a Party seeks such judicial relief but fails to obtain it, the Party seeking such relief shall pay the reasonable attorneys' fees and costs of the other Party incurred with respect to opposing such relief.

The Parties agree that execution of this Agreement will further enable the Parties to address many of the specific tasks that are required prior to the creation of a functioning Market by one or both of the Parties. Specifically, Articles III through XII of this Agreement detail certain assignments that may pertain to the reliability and administration of adjacent energy markets. To ensure efficient handling of tasks hereunder the Parties agree to cooperate in good faith to address further protocols that may be required to facilitate each Party’s efforts to administer its respective markets.

This Agreement does not modify any prior agreement with either Party's Transmission Owners with regard to revenue distribution. All distribution of revenue received under this agreement shall be distributed by the Party receiving such revenue in accordance with the terms of such Party's prior agreement with their Transmission Owners.

Except as specifically set forth in this Agreement, each Party shall render invoices to the other Party for amounts due under this Agreement in accordance with its customary billing practices (or as otherwise agreed between the Parties) and payment shall be due in accordance with the invoicing Party's customary payment requirements (unless otherwise agreed). All payments shall be made in immediately available funds payable to the invoicing Party by wire transfer pursuant to instructions set out by the Parties from time to time. Interest on any amounts not paid when due shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

Each Party grants the other Party, acting through its officers, employees and agents such access to the books and records of the other as is necessary to audit and verify the accuracy of charges between the Parties under this Agreement. Such access shall be at the location of the Party whose books and records are being reviewed pursuant to this Agreement and shall occur during regular business hours.

This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, between two independent entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations between the Parties except as specified expressly herein. All obligations hereunder shall be subject to and performed in a manner that complies with each Party's internal requirements; provided, however, this sentence shall not limit either Party's payment obligation under Article XVI or indemnity obligation under Section 18.3.1 or Section 18.3.2, respectively.

Section 17.2 Agreement to Jointly Make Required Tariff Changes to Implement Agreement.

The Parties agree that they shall cooperate in good faith in the filing of any Section 205 filings before FERC that may be required to implement the terms of this Agreement to facilitate the Effective Date. Whenever practicable, the Parties agree that they shall make simultaneous filings with FERC concerning such Tariff filings.

The term “Confidential Information” shall mean: (a) all information, whether furnished before or after the Effective Date, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked “confidential” or “proprietary” or which under all of the circumstances should be treated as confidential or proprietary; (b) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; and (c) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC’s Standards of Conduct set forth in 18 CFR § 37 et seq. and the Parties’ Standards of Conduct on file with the FERC.

During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its subcontractors and its subcontractors' employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Section by its employees, its subcontractors and its subcontractors' employees and agents. This obligation of confidentiality shall not extend to information that, at no fault of the recipient Party, is or was (1) in the public domain or generally available or known to the public; (2) disclosed to a recipient by a third party who had a legal right to do so; (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel, in which event the recipient hereby agrees to provide the issuing Party with prompt Notice of such request or requirement in order to enable the issuing Party to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event that such protective order or other remedy is not obtained, or that the issuing Party waives compliance with the provisions hereof, the recipient hereby agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

(a) All Intellectual Property (as defined below), and modifications to, and enhancements of, and derivatives of such Intellectual Property (i) owned by a Party on or before the effective date of this Agreement; or (ii) developed by a Party after the effective date of this Agreement, shall remain the sole property of such Party, and no right, title or interest to such Intellectual Property shall be granted to any other Party.

(b) Except as expressly set forth in a subsequent binding agreement, no Party shall use, convey or disclose the Intellectual Property of another Party without the express written consent of such other Party and nothing herein shall be construed to be a license or other transfer by a Party of any Intellectual Property or interests therein to another Party.

(c) For purposes of this Agreement:

- "Intellectual Property" means all patent rights (including patent applications, disclosures and Inventions (as defined below), rights of priority, mask work rights, copyrights, moral rights, trade secrets, know-how and any other intellectual property rights recognized in any country or jurisdiction of the world including trademarks, trade names, logos, service marks, and other designations of source; and
- "Inventions" means any idea, design, concept, technique, method, discovery or improvement conceived of and actually or constructively can be reduced to practice for which a patent application is or may be filed in the United States or in any foreign country, or for which a patent has issued in the United States or in any foreign country.

SPP will defend, indemnify and hold MISO harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against MISO, only to the extent such Losses arise directly from:

(a) gross negligence, recklessness, or willful misconduct of SPP or any of SPP's agents or employees, on the performance of this Agreement, except to the extent the Losses arise from (i) gross negligence, recklessness, willful misconduct or breach of contract or law by MISO or any of MISO's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon MISO or MISO's agents or employees;

(b) Any claim that MISO violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.; and

(d) Any claim that SPP caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of MISO.

MISO will defend, indemnify and hold SPP harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against SPP, only to the extent such Losses arise directly from:

(a) gross negligence or recklessness, or willful misconduct of MISO or any of MISO's agents or employees, in the performance of the Agreement, except to the extent the Losses arise from (i) gross negligence, recklessness, willful misconduct or breach of contract or law by SPP or any of SPP's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon SPP or SPP's agents or employees;

(b) Any claim that SPP violated any copyright, patent, trademark, license, or other intellectual property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.; and

(d) Any claim that MISO caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of SPP.

Except for amounts agreed to be paid under Article XVI by one Party to the other under this Agreement, and except for amounts due under Sections 18.3.1 and 18.3.2, no Party shall be liable to the other Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform this Agreement, unless such failure to perform was malicious or reckless. The limitation of liability shall not apply to billing adjustments for errors in invoiced amounts due under this Agreement, provided such billing adjustments are made within the claims limitation period under Section 18.3.4 of this Agreement.

Except for amounts agreed to be paid by one Party to the other under this Agreement, and except for amounts due under Sections 18.3.1 and 18.3.2, any liability of a Party to the other Party hereunder shall be limited to direct damages as qualified by the following sentence. No lost profits, damages to compensate for lost goodwill, consequential damages, or punitive damages shall be sought or awarded.

No claim seeking an adjustment in the billing for any service, transaction, or charge under this Agreement may be asserted with respect to a month, if more than one year has elapsed since the first date upon which the invoice was rendered for the billing for that month. A Party shall make no adjustment to billing with respect to a month for any service, transaction, or charge under this Agreement, if more than one year has elapsed since the first date upon which the invoice was rendered for the billing for that month, unless a claim seeking such adjustment had been received by the Party prior thereto.

The term of this Agreement commences upon its acceptance or approval by FERC. The Agreement shall terminate and cease to be effective upon FERC acceptance of the mutual agreement by the Parties to terminate the Agreement or other FERC order terminating the Agreement. Nothing in this Agreement shall prejudice the right of either Party to seek termination of this Agreement under Section 206 of the Federal Power Act, or successor section or statute thereof.

Upon termination or expiration of this Agreement for any reason or in accordance with its terms, the following Articles and Sections shall be deemed to have survived such termination or expiration:

Article II - (Definitions and Rules of Construction)
Article XVI - (Accounting and Allocation of Costs of Joint Operations)
Article XVII- (Retained Rights of the Parties)
Article XVIII- (Additional Provisions), except Section 18.11 (Execution of Counterparts) and Section 18.12 (Amendment)

This Agreement is intended solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on, any third party (other than the Parties' successors and permitted assigns).

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns permitted herein, but shall not be assigned except (a) with the written consent of the non-assigning Party, which consent may be withheld in such Party's absolute discretion; and (b) in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. In the case of any merger, consolidation, reorganization, sale, or spin-off by a Party, the Party shall assure that the successor or purchaser adopts this Agreement and, the other Party shall be deemed to have consented to such adoption.

No Party shall be in breach of this Agreement to the extent and during the period such Party's performance is made impracticable by any unanticipated cause or causes beyond such Party's control and without such Party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities. Upon the occurrence of an event considered by a Party to constitute a *force majeure* event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall require no Party to settle any strike or labor dispute. A Party claiming a *force majeure* event shall notify the other Party in writing immediately and in no event later forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

This Agreement shall be interpreted, construed and governed by the applicable federal law and the laws of the state of Delaware without giving effect to its conflict of law principles.

Whether expressly so stated or not, all notices, demands, requests and other communications required or permitted by or provided for in this Agreement ("Notice") shall be given in writing to a Party at the address set forth below, or at such other address as a Party shall designate for itself in writing in accordance with this Section, and shall be delivered by hand or reputable overnight courier:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: General Counsel

Midcontinent Independent System Operator, Inc.

For Parcels:	For U.S. Mail:
720 City Center Drive	P.O. Box 4202
Carmel, IN 46032	Carmel, IN 46082-4202
Attention: General Counsel	Attention: General Counsel

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon the Parties hereto, notwithstanding that both Parties may not have executed the same counterpart.

Except as may otherwise be provided herein, neither this Agreement nor any of the terms hereof may be amended unless such amendment is in writing and signed by the Parties and such amendment has been accepted by FERC.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Southwest Power Pool, Inc.
By: *<u>/s/ Nicholas A. Brown</u>*
Name: Nicholas A. Brown
Title: President and CEO

Date: December 1, 2004

Midwest Independent Transmission System Operator, Inc.
By: *<u>/s/ James P. Torgerson</u>*
Name: James P. Torgerson
Title: President and CEO

Date: December 1, 2004

ARTICLE XIX CHANGE MANAGEMENT PROCESS

Section 19.1 Notice.

Prior to making a change to i) any processes that would affect the implementation of the market-to-market process under this Agreement, including the determination of market-to-market settlements; or ii) a change to the calculation methodology of Market Flow and Firm Flow Limits/Firm Flow Entitlements, and tagged transaction impacts of imports and exports in IDC. The Party desiring the change shall notify the other Party in writing or via email of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change will have on i) the implementation of the market-to-market process, including market-to-market settlements, and ii) calculation methodology of Market Flow and Firm Flow Limits/Firm Flow Entitlements, and the tagged transaction impacts of imports and exports in IDC under this Agreement.

Section 19.2 Response to Notice.

Within 30 days after receipt of the Notice described in Section 19.1, the receiving Party shall: (a) notify in writing or by email the other Party of its concurrence with the proposed change; (b) request in writing or via email additional documentation from the other Party, including associated test documentation; (c) notify in writing or via email the other Party of its disagreement with the proposed change and request that issue regarding the proposed change be addressed pursuant to the dispute resolution procedures set forth in Article XIV of this Agreement. In the event that the receiving Party requests additional documentation as described in (b), within 30 days after receipt of such information, it shall notify the other Party in writing or via email that it concurs with the change or that it requests dispute resolution pursuant to Article XIV of this Agreement.

Section 19.3 Implementation of Change.

The Party proposing a change to its market-to-market implementation process or to the calculation methodology of Market Flow and Firm Flow Limits/Firm Flow Entitlements, and the tagged transaction impacts of imports and exports in IDC shall not implement such change until it receives written or email notification from the other Party that the other Party concurs with the change or until completion of any dispute resolution process initiated pursuant to Article XIV of this Agreement. Neither Party shall unduly delay its obligations under this Article XIX so as to impede the other Party from timely implementation of a proposed change.

Section 19.4 Summary of Proposed Changes.

On a quarterly basis, the Parties shall post on their respective websites a summary of market-to-market implementation process changes or changes to the calculation methodology of Market Flow and Firm Flow Limits/Firm Flow Entitlements, and the tagged transaction impacts of imports and exports in IDC proposed by the Parties in the prior quarter and the status of such changes.

ARTICLE XX BIENNIAL REVIEW OF PROCESS CHANGES

Commencing no later than one year after implementation of Attachment 2 to this Agreement, the Parties shall conduct a comprehensive review of the changes made to each Party's processes used to implement Attachment 2 to this Agreement. A comprehensive review shall be conducted by the Parties at least every other year following the initial comprehensive review.

The Parties shall post the results of the initial and each subsequent biennial comprehensive review on their respective websites.

ATTACHMENT 1

Congestion Management Process (CMP) MASTER

Baseline
Version 1.11

Executive Summary

This Congestion Management Process[1] document provides significant detail in the areas of Market Flow Calculation. These additional details are the result of discussions between multiple Operating Entities.

As Operating Entities 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. This proposed solution will greatly enhance current Interchange Distribution Calculator (IDC) granularity by utilizing existing real-time applications to monitor and react to Flowgates external to an Operating Entity's footprint.

In brief, the process includes the following concepts:

- Participating Operating Entities will agree to observe limits on an extensive list of coordinated external Flowgates.
- Like all Control Areas (CA), Market-Based Operating Entities will have Firm and non-Firm GTL flows upon those Flowgates.
- In real-time, Market-Based Operating Entities will calculate and monitor one-hour ahead projected and actual flows.
- The IDC will calculate GTL flows for Operating Entities using the State Estimator data provided by the entities.
- Market-Based Operating Entities will calculate the actual and the one-hour ahead projected Firm and non-Firm limits for both internal and external Coordinated Flowgates.
- Market-Based Operating Entities will constrain their operations to limit Firm GTL flows on the Coordinated Flowgates to no more than the calculated Firm Flow Limit established in the analysis.
- 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 transactions into the market, transactions out of the market, transactions through the market, and tagged grandfathered transactions within the market.
- When there is a Transmission Loading Relief (TLR) 3a request or higher called on a Coordinated Flowgate, and the Market-Based Operating Entity's actual/one-hour ahead projected IDC GTL flows exceed the Firm Flow Limits, Market-Based Operating Entities will respond to their relief obligations by redispatching their systems in a manner that is consistent with how non-market entities respond to their share of IDC GTL relief obligations per the IDC congestion management report.

[1] Capitalized terms that are not defined in this Attachment 1 shall have the meaning set forth in the body, appendices, and attachments of the *Joint Operating Agreement Between Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc.*

- The above processes refer to the “Congestion Management” portion of the paper, which will be implemented by Market-Based Operating Entities.
- Additional entities may choose to enter into similar Reciprocal Coordination Agreements that describe how Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), Firm Flows, and outage maintenance will be coordinated on a forward basis.
- The complete process will allow participating 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.

Change Summary

Generate baseline Congestion Management Process (CMP) document based on CMP documents executed by:

- Manitoba Hydro and Midcontinent Independent System Operator, Inc. (MISO)
- Mid-Continent Area Power Pool (MAPP) and MISO
- MISO and PJM Interconnection, L.L.C. (PJM)
- MISO, PJM and Tennessee Valley Authority (TVA)
- MISO and Southwest Power Pool, Inc. (SPP)

The document also includes subsequent changes agreed upon by a majority of the Congestion Management Process Council (CMPC). For items which are specific to a limited number of agreements, the CMP members have used an approach of documenting these unique items in separate appendices rather than in the base document. The CMPC members reserve all rights with respect to the different options identified in the appendices attached hereto without any obligation to adopt or support such options. The CMPC members reserve the right to oppose any position taken by another CMPC member in a FERC filing or otherwise with respect to the choice of options listed in the appendices. Nothing contained herein shall be construed to indicate the support or agreement by the CMPC members to an option presented in the appendices.

Revision 1.1 (November 30, 2007)

Per FERC Order ER07-1417-000, in the "Forward Coordination Processes" section 6.6 added the word "outage" between "unit" and "scheduling" in the following sentence, "Market-Based Operating Entities will use the Flowgate limit to restrict unit outage scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate."

Revision 1.2 (May 2, 2008)

The Market Flow Threshold is changing from 3% to 5%. The NERC Standards Committee approved changing the Market Flow Threshold for the field test at its April 10, 2008 meeting.

Revision 1.3 (July 16, 2008)

Per FERC Order issued in Docket Nos. ER08-884-000 and ER08-913-000, *Appendix H (Market Flow Threshold Field Test Terms And Conditions)* was added.

Revision 1.4 (October 31, 2008)

The percentages were changed in Sections *4.4 (Firm Market Flow Calculation Rules) and 5.5 (Market-Based Operating Entity Real-time Actions)* to be consistent with changes made under

Revision 1.2. *Appendix H – Market Flow Threshold Field Test Terms And Conditions* was updated to reflect the NERC approved Market Flow Threshold Field Test extension to October 31, 2009.

Revision 1.5 (December 18, 2008)

Updated Section 5.2 (*Quantify and Provide Data for Market Flow*) and *Appendix B – Determination of Marginal Zone Participation Factors* to support changes to the manner in which MISO uses marginal zones and submits marginal zone information to the IDC.

Revision 1.6 (February 19, 2009)

Appendix H – Market Flow Threshold Field Test Terms And Conditions was updated to reflect that MISO no longer has a contractual obligation to observe a 0% threshold for MISO Market Flows on Flowgates where both MAPP and MISO are reciprocal.

Revision 1.7 (November 1, 2009)

Applied updates based on the results of the Market Flow Threshold Field Test including clarifications that allocations are calculated down to zero percent. Changes have been applied to the *Executive Summary, Section 4.1 Market Flow Determination, Section 4.4 Firm Market Flow Calculation Rules, Section 5.5 Market-Based Operating Entity Real-time Actions, Section 6.6 Forward Coordination Processes, Section 6.6.3 Limiting Firm Transmission Service, Section 6.7 Sharing or Transferring Unused Allocations, and Appendix H – Application of Market Flow Threshold Field Test Conditions*.

Revision 1.8 (May 31, 2010)

Applied updates to further standardize the “Allocation Adjustment for New Transmission Facilities and/or Designated Network Resources” process. Changes have been made to *Appendix F – FERC Dispute Resolution* and *Appendix G – Allocation Adjustments for New Transmission Facilities and/or Designated Network Resources.*

Revision 1.9 (July 25, 2016)

Generated updated baseline CMP document executed by the following entities:

- Manitoba Hydro and MISO
- Minnkota Power Cooperative, Inc. and MISO
- MISO and PJM
- PJM and TVA
    - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU) and Associated Electric Cooperative, Inc. (AECI) executed

separate agreements with TVA stipulating the CMP provisions executed by PJM and TVA apply to AECI and LG&E/KU as Reciprocal Entities.

- MISO and SPP
- MISO Attachment LL

Section	Revision Description
3.2	Clarified language on inclusion of Coordinated Flowgates in AFC process. Removed consideration of reverse impacts when performing Flowgate studies.
3.2.1	Revised language to better describe how the four Flowgate studies used to identify Coordinated Flowgates are performed.
3.2.6	Added a new section requiring coordination between Parties before making a Flowgate permanent that includes a Tie Line monitored element.
4.1 4.1.1	Revised language to require a Market-Based Operating Entity to consistently account for export and import tagged transactions in the identified calculations using one of the three methodologies set forth in the new Section 4.1.1. Revisions have previously been accepted by FERC in the CMP documents executed between MISO and PJM, MISO and SPP, and PJM and TVA.
6.10	Added a new section listing the requirements that must be satisfied for a Combining Party to incorporate a Non-Reciprocal Entity's load and the associated generation serving that load into the Reciprocal's Entity's Allocation calculations.
Appendix A	Added the following defined terms: Agreement, Combining Party, Non-Reciprocal Entity, Party, Third-Party, and Tie Line.
Appendix B	Revised language addressing how a Market-Based Operating Entity using the Marginal Zone methodology will determine marginal zone participation factors. Revisions have previously been accepted by FERC in the CMP documents executed between MISO and PJM, MISO and SPP, and PJM and TVA.
Appendix C	Clarified in Figure C-1 and Table C-1 the steps on inclusion of Coordinated Flowages in the AFC process.

Revision 1.10 (June 1, 2017)

Per NERC Operating Reliability Subcommittee applied updates necessary for MISO to incorporate External Asynchronous Resources into MISO Market Flows.

Section	Revision Description
3.2	Updated the number of Coordination Flowgate studies from four to five.

3.2.1	Clarified Study 4 applies internal CA/CA permutations and added a new Study 5 specific to External Asynchronous Resources.
3.2.2	Updated the number of Coordination Flowgate studies from four to five.
3.2.5	
4.1	Added how the External Asynchronous Resources will be considered in Market Flow and the exclusion of the related tags from IDC.
6.2	Updated the number of Coordination Flowgate studies from four to five.
6.8	Specified the priority of the Market Flow will correspond to the priority of the tag.
Appendix A	Added a new definition specific to MISO, External Asynchronous Resources. Updated the number of Coordination Flowgate studies from four to five.
Appendix C	Updated the number of Coordination Flowgate studies from four to five in Table C-1.

Revision 1.11 (June 2, 2022)

Updated to reflect the PFV changes as per NAESB Standards.

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SECTION 7 – APPENDICES

1 Introduction

It is the intention of the Reciprocal Entities to utilize the processes within this document. It is further the intention to develop this process in a way that will allow other regional entities with similar concerns to utilize the concepts within this process to aid in the resolution of their own seams issues.

1.1 Problem Definition

1.1.1 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 to transport that energy, and a specific sink point where that energy is being consumed by a load. However, due to the electrical characteristics of the Eastern Interconnection, energy flows are more dispersed 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 North American Electric Reliability Corporation (NERC) and/or North American Energy Standards Board (NAESB) TLR process. Through this process, Reliability Coordinators utilize the 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 specifies 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. Bid-based security constrained central dispatch based on Locational Marginal Pricing is a regional implementation of this practice.

Currently, these two practices are somewhat incompatible. 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 operational disjoint, as the expansion itself exacerbates the negative effects of the incompatibility.

1.1.2 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.

1.1.3 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; that is, the apparent Control Area boundary becomes the same as the market boundary so that what had been historically 30 or more Control Areas now appears as one.

In the first change, transactions contained entirely within the market footprint are considered to be utilizing network service (even when the market spans multiple Control Areas). As such, there is no requirement for them to be tagged (or such requirement is waived by NERC), and therefore, no requirement that they be sent to the IDC. This is of concern from a reliability perspective, as the IDC will no longer have a large 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 dilution of the approximation utilized by the IDC. When a market region is relatively small (or isolated), the Control Area to Control Area 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, and is co-mingled with non-market Control Areas, the ability to utilize the historic approximation of electrically representative flows fails to effectively predict energy flow. 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.”

1.1.4 Accounting for Loop Flows

The processes for accounting for loop flows caused by uses of the transmission system between Control Areas are different under a market environment. Absent a market, loop flows from Transmission Service reservations between Control Areas are identified and accounted for by importing transmission reservations from surrounding systems. Under a market environment, the market will not have explicit transmission reservations for evolving market dispatch conditions between market Control Areas. Thus, a mechanism for accounting for anticipated Market Flows on non-market systems is necessary.

1.1.5 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 effectiveness of a curtailment to provide that relief and the general pool of transactions available for curtailment are reduced. This CMP offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the IDC for the market area. This new congestion management process will ensure that reliability is not adversely affected as markets expand by providing information and relief opportunities previously unavailable to the IDC.

1.2 Process Scope and Limitations

1.2.1 Vision Statement

As Operating Entities become Market-Based Operating Entities, and expand 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 and equitability. Reliability Coordinators can mandate emergency procedures to maintain safe operating limits, however, without coordination agreements that maintain flow limits in advance, the market would become volatile and the burden for relieving excess flow would ignore the economics of the entities which would be required to redispatch. For these entities, this process will offer a manner in which Market-Based Operating Entities can coordinate parallel flows with Operating Entities that have not yet or do not contemplate implementing markets. This process 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.

1.2.2 Process Scope

This process has been written specifically with the goal of coordinating seams between Reciprocal Entities and their respective neighbors.

1.3 Goals and Metrics

This document focuses on a solution to meet the following goals and requirements:

1. Develop a congestion management process whereby transmission overloads can be prevented through a shared and effective reduction in Flowgate or constraint usage by Reciprocal Entities and adjoining Reliability Coordinators.

2. Agree on a predefined set of Flowgates or constraints to be considered by all Reciprocal Entities, and a process to maintain this set as necessary.

3. Determine the best way to calculate flow due to market impacts on a defined set of Flowgates.

4. Develop Reciprocal Coordination 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. This process will include both operating horizon determination as well as forward looking capacity allocation.

5. Develop a procedure for managing congestion when Flowgates are impacted by both tagged and untagged energy flow.

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

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

8. Determine whether procedure(s) for managing congestion will differ based on where the Flowgate is located (*i.e.*, inside Reciprocal Entity A, inside Reciprocal Entity B, or outside both Reciprocal Entity A and Reciprocal Entity B).

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

10. Develop methodology to preserve and accommodate grandfathered transmission rights, contract rights, and other joint-use agreements.

11. Develop methodology to address changes in Total Transfer Capability (TTC), such as future system topology changes, new Designated Network Resources (DNRs), facility uprates/derates, prior outage limitations, etc., with respect to Allocation implications.

12. Develop a methodology for releasing Allocations if other parties do not join the process or if there is ATC going unused.

1.4 Assumptions

The processes set forth in this document were based on the following assumptions:

- Point-to-point schedules sinking in, sourcing from, or passing through an Operating Entity will be tagged.

- The IDC or a similar repository of schedules is needed at the Interconnection's current state and for the foreseeable future.

- The Operating Entity's Energy Management System (EMS) has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch.

- 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.

- The IDC has been modified to accept the submitted values of real-time generation, load, and other real-time data.

- The IDC calculates the impacts of the untagged dispatch (GTL) on the Flowgates for all Operating Entities using Parallel Flow Visualization (PFV).

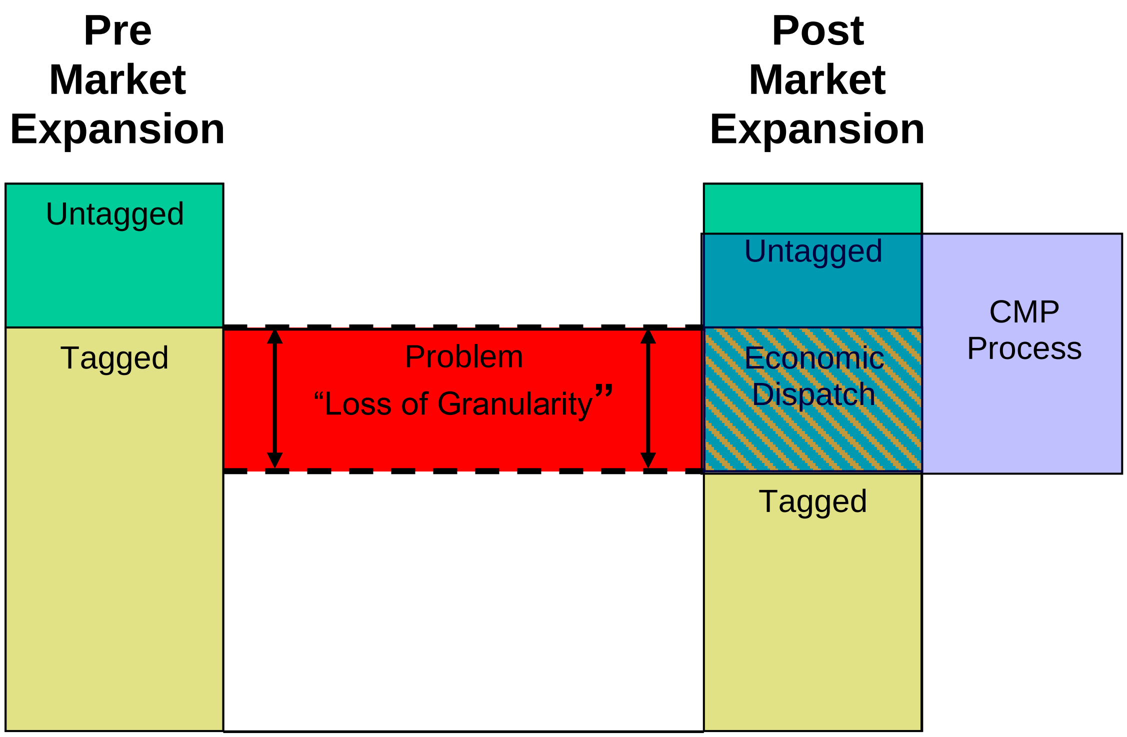
- The IDC will determine the Firm and non-Firm GTL flow for each Market-Based Operating Entity using the Firm and non-Firm limits calculated in this agreement.

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

2 Process Overview

2.1 Summary of Process

In order to coordinate congestion management, a bridge must be established that provides for comparable actions between Operating Entities. Without such a bridge, it is difficult, if not impossible, to ensure reliability and system coordination in an efficient and equitable 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.



GTL flows are the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an Operating Entity's Control Area. (Note: For the purposes of the Reciprocal Coordination process discussed later, Firm Transmission Service (7F) will be combined with the untagged firm component of Market Flows in the calculation of Historic Firm Flow. The Historic Firm Flow is described later in this document).

The IDC currently calculates GTL flows for each CA in the Eastern Interconnection and used to determine each Operating Entities curtailment under a TLR. The methodology defined in this document determines how to quantify these GTL flows as Firm and non-Firm for each Market-Based Operating Entity. Market Flow is a calculation similar to GTL, but is no longer used to determine relief obligations in the TLR protocol. However, Market Flow may still be used for congestion management between Market-Based Operating Entities, and thus we continue to define it in this agreement for reference.

GTL flows can be divided into Firm and Non-Firm. Firm GTL flows are considered as firm use of the transmission system for congestion management purposes and will be curtailed on a proportional basis with other firm uses during periods of firm curtailments and are equivalent to Firm Transmission Service. Non-Firm GTL flows are considered as non-firm use of the transmission system for congestion management purposes and will be curtailed on a proportional basis with other non-firm uses during periods of non-firm curtailments and are equivalent to non-firm Transmission Service. As such, Reliability Coordinators can request Market-Based Operating Entities to 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 market prices.

There are two areas that must be defined in order for this process 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 energy 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 coordination will result in a reduction of TLR 5 events, as more relief will be available in TLR 3 to mitigate a constraint. This is accomplished through the calculation of flows due to economic dispatch, as well as by providing marginal unit information to aid in interchange transaction management.

The next sections of this document discuss each of these areas in detail.

3 Impacted Flowgate Determination

3.1 Flowgates

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize Flowgates in various capacities to coordinate operations and manage reliability. For the purpose of this process, there are three kinds of Flowgates: AFC Flowgates, which are defined in Appendix A, Coordinated Flowgates (CFs), which are defined below, and Reciprocal Coordinated Flowgates (RCFs), which are defined in "Reciprocal Operations" Section 6. A diagram illustrating how these three categories of Flowgates are determined is included as Appendix C.

3.2 Coordinated Flowgates

An Operating Entity will conduct sensitivity studies to determine which Flowgates are significantly impacted by the flows of the Operating Entity's Control Zones (historic Control Areas that existed in the IDC). An Operating Entity identifies these Flowgates by performing the following five studies to determine which Flowgates the Operating Entity will monitor and help control. As set forth in Appendix C, a Flowgate passing any one of these studies will be considered a Coordinated Flowgate and AFCs shall be computed for these Flowgates, unless mutually agreed otherwise by the Operating Entities and any Reciprocal Entities for the Flowgate. An Operating Entity shall add a Coordinated Flowgate to its AFC process as soon as practical in accordance with the Operating Entity's processes. Nothing in this section precludes an Operating Entity or Reciprocal Entity from calculating AFCs for any Flowgates.

An Operating Entity may also specify additional Flowgates that have not passed any of the five studies to be Coordinated Flowgates where the Operating Entity expects to utilize the TLR process to manage congestion. For a list of Coordinated Flowgates between Reciprocal Entities, see each Reciprocal Entity's Open Access Same-Time Information System (OASIS) website.

Coordinated Flowgates are identified to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the congestion management processes and/or Reciprocal Operations defined in this document.

When performing the five Flowgate studies, a 5% threshold will be used based on the positive impact. Use of a 5% threshold in the studies may not capture all Flowgates that experience a significant impact due to operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC and/or NAESB implements the use of a lower threshold in the TLR process.

3.2.1 Flowgate Studies

Study 1) – IDC GLDF

(using the IDC tool)
Upon request by an Operating Entity, a study will be performed using the IDC reflecting the topology of the system from the System Data Exchange (SDX) or any industry-accepted system with similar capabilities. The IDC can provide a list of Flowgates for any user-specified Control Area whose Generator to Load Distribution Factor (GLDF) NNL impact is 5% or greater. Using the historic Control Area representation in the IDC, if any one generator has a GLDF that is 5% or greater as determined by the IDC, this Flowgate will be considered a Coordinated Flowgate.

Study 2) – IDC PSS/E Base Case GLDF

(no transmission outages – offline study)
Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a generator analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. To provide better confidence that the Operating Entity has effectively captured the subset of Flowgates upon which its generators have a significant impact, the Operating Entity will perform an offline study utilizing Managing and Utilizing System Transmission (MUST) or other industry-accepted software with similar capabilities. The Operating Entity will perform off-line studies using the IDC PSS/E base case. If any generator has a GLDF that is 5% or greater as determined by this Study 2, this Flowgate will be considered a Coordinated Flowgate. Study 1 above and this Study 2 are separate studies. There is no requirement that a Flowgate must pass both studies in order to be coordinated.

Study 3) – IDC PSS/E Base Case GLDF

(transmission outage - offline study)
Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a Flowgate analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Flowgates determined using Study 2 above or Study 4 below that have a 3% to 5% distribution factor will be analyzed in this Study 3 against prior outage conditions. The Operating Entity will perform off-line studies using the IDC PSS/E base case utilizing MUST or other industry-accepted software with similar capabilities. The Operating Entity, in consultation with affected operating authorities, will perform a prior outage analysis, including both internal and external outages by applying one of the following:

1. transmission facilities operated at 100kV and above, in the CA where the Flowgate's monitored facility(ies) is located and in CAs that are first tier to the CA where the Flowgate's monitored facility(ies) is located; or

2. transmission facilities operated at 100kV and above within 10 buses from the monitored facility(s).

If any Flowgates with a 3% to 5% distribution factor from Study 2 or Study 4 are impacted by 5% or more from a prior outage condition (Line Outage Distribution Factor (LODF)) from this Study 3, the Flowgate will be added to the list of Coordinated Flowgates.

Study 4) – IDC Base Case Transfer Distribution Factors

(no transmission outages – offline study)
Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a Flowgate analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity performing this analysis will analyze internal transactions between each historic CA/CA permutation. OTDF Flowgates will be analyzed with the contingent element out of service. The Operating Entity will perform off-line studies using the IDC PSS/E base case utilizing MUST, or other industry-accepted software with similar capabilities to determine the Transfer Distribution Factors (TDFs). Flowgates that are impacted by 5% or greater by Study 4 will be considered a Coordinated Flowgate.

Study 5) – External Asynchronous Resource (EAR)

Upon request by an Operating Entity, MISO shall rerun Study 4 (no outage scenario) to determine the flowgates impacted by its EAR. Additionally, a second study will be performed using the IDC reflecting the topology of the system from the System Data Exchange (SDX) or any industry-accepted system with similar capabilities. Both studies performed under Study 5 shall utilize the following assumptions: 1) the source to sink TDF calculation of the EAR shall be evaluated in the same way IDC would evaluate the impacts of the associated tag (e.g., source and sink of the EAR); and 2) any flowgate that is determined to be impacted by the EAR by 5% or greater will be considered a Coordinated Flowgate.

3.2.2 Disputed Flowgates

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

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

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

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

3.2.3 Third Party Request Flowgate Additions

Each Party shall provide opportunities for Third Parties or other entities to propose additional Coordinated Flowgates and procedures for review of relevant non-confidential data in order to assess the merit of the proposal. The current procedure for the review and maintenance of Coordinated Flowgates is set forth in Appendix C.

3.2.4 Frequency of Coordinated Flowgate Determination

The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then on a periodic basis, as described in Appendix C.

3.2.5 Dynamic Creation of Coordinated Flowgates

For temporary Flowgates developed "on the fly," the IDC will calculate GTL relief obligation based on GPS or TSNT method and once market entities submit the Firm Flow Limits the GTL relief obligation will be based on submitted Firm Flow Limits on the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will study the Flowgate in a timely manner and begin reporting Flowgate data within no more than two business days (where the Flowgate has already been designated as an AFC Flowgate). This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the five studies detailed earlier in this document and determine the Flowgate's relationship with the Market-Based Operating Entity's dispatch. For internal Flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Limits; during a TLR 5, the IDC will request GTL relief obligation in the same manner as today. Alternatively, for internal and external Flowgates, an Operating Entity may utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary Flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary Flowgate's monitored element and with the same contingent element. If the Flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. The necessary criteria for adding a Flowgate are defined in Appendix C. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entities will coordinate respective actions to provide immediate relief until final review.

3.2.6 Coordination of Tie Line Flowgate Additions

The Parties shall follow the coordination process outlined in this section for Flowgates that include a Tie Line between the Parties as a monitored element. The provisions in this section shall not apply to any temporary Flowgates.

Procedures:

1. Unless otherwise agreed to by the Parties, the managing entity for a Tie Line Flowgate is the Party that has functional control over the most limiting equipment for the Flowgate.

2. The managing entity for a Tie Line Flowgate shall calculate AFCs, post AFCs, process requests for transmission service, manage real-time congestion, and calculate Allocations for the Tie Line Flowgate.

3. Before the creation of a new Tie Line Flowgate in the IDC, the managing entity for the Tie Line Flowgate must notify the other Party no less than sixty (60) days in advance of the addition of the Tie Line Flowgate in the IDC. The new Flowgate will initially be created as a temporary Flowgate in the IDC by the managing entity. If all other requirements outlined in this Section 3.2.6 are completed during the sixty (60) days following notice, the Flowgate can be made permanent before the sixty (60) day deadline by mutual agreement of the Parties.

4. A Party that identifies a new Tie Line Flowgate through a study shall provide the study assumptions, methodology, and all other relevant data to the other Party in a timely manner.

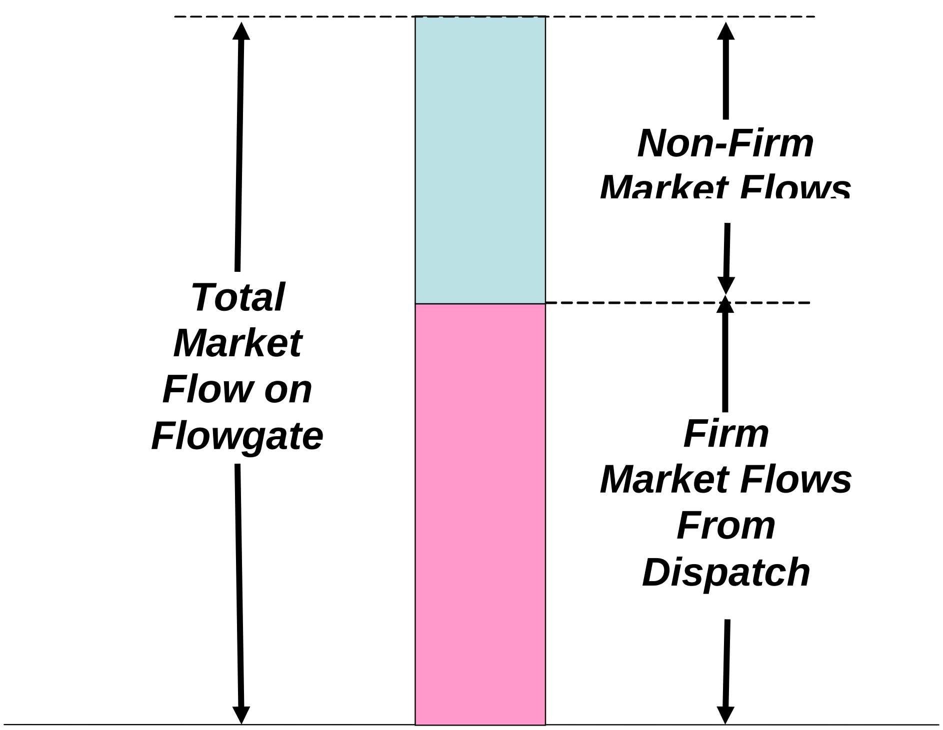
5. AFC Calculation and Posting AFCs:
    a. The managing entity will calculate and post AFCs for Tie Line Flowgates in accordance with the managing entity's processes (i.e., the managing entity will treat the Flowgates as internal Flowgates).
    b. The managing entity will post AFC files for Tie Line Flowgates for use by other transmission providers.
    c. The managing entity will apply AFC factors for Tie Line Flowgates (e.g., TRM, CBM, "a" and "b" multipliers, etc.) using the managing entity's own processes.

6. Upon the completion of items 1 through 5, the managing entity may create a permanent Tie Line Flowgate.

7. The Party that is not the managing entity will replace the temporary Tie Line Flowgate with the permanent Tie Line Flowgate in its applicable operating system(s).

Section 4 Market-Based Operating Entity Flow Calculations: Market Flow, Firm Market Flow, and Non-Firm Market Flow

Market Flows on a Coordinated Flowgate can be quantified and considered in each direction**.** Market Flow is then further designated into two components: Firm Market Flow, which is energy flow related to contributions from the Network and Native Load serving aspects of the dispatch, and Non-Firm Market Flow, which is energy flow related to the Market-Based Operating Entity's market operations.



Note: Market flows equal generation to load flows in market areas.

Each Market-Based Operating Entity will calculate their actual real-time and projected directional Market Flows, as well as their directional Firm and Non-Firm Market Flows, on each Coordinated Flowgate. The following sections outline how these flows will be computed.

Section 4.1 Market Flow Determination

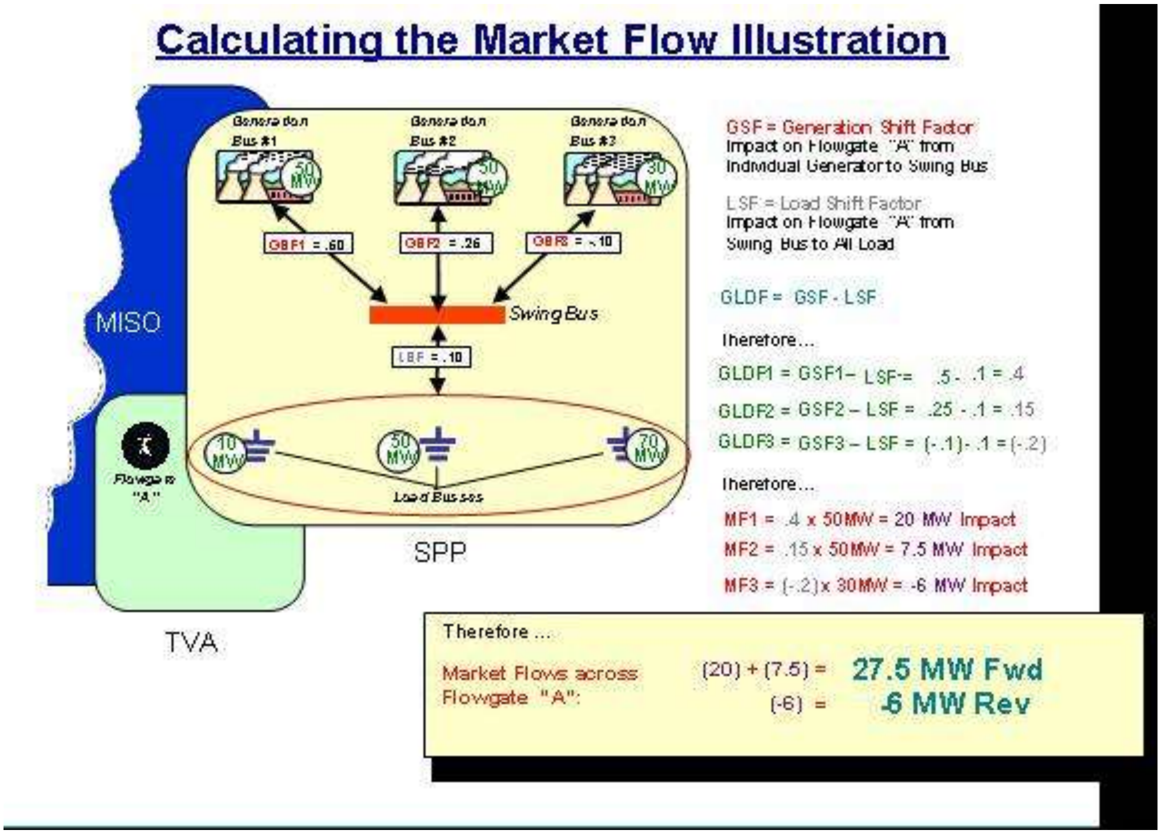
The determination of Market Flows builds on the "Per Generator" methodologies that were developed by the NERC Parallel Flow Task Force. The "Per Generator Method Without Counter Flow" was presented to and approved by both the NERC Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC).[1]

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 calculated in each direction; forward Market Flows is the sum of the positive Market Flow contributions of each generator within the market area, while reverse Market Flow is the sum of the negative Market Flow contributions of each generator within the market area.

For purposes of the Market Flow determination, the market area may be either: (1) the entire RTO footprint, as in the following illustration; or (2) a subset of the RTO region, such as a pre-integration NERC-recognized Control Area, as necessary to ensure accurate determinations and consistency with pre-integration flow determinations. Each Market-Based Operating Entity shall choose only one of these two options to calculate its Market Flows. With regard to the second option, the total Market Flow of an RTO shall be the sum of the flows from and between such market areas.

[1] "Parallel Flow Calculation Procedure Reference Document," NERC Operating Manual. 11 Feb, 2003. www.nerc.com



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 5% or greater 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 flows, in both directions, to calculate a Market Flow down to a 5% threshold and to calculate a Market Flow down to a 0% threshold. Forward flows and reverse flows are determined as discrete values.
- 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 to the "Per Generator Method," while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force.

Directional flows are required for this process 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, but are considered as distinct directional flows to ensure comparability with existing NERC and/or NAESB TLR processes. Under this process, the use of real-time values in concert with the Market Flow calculation effectively implements one of the more accurate and detailed methods of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force.

Each Market-Based Operating Entity shall choose one of the three methodologies set forth in Section 4.1.1 (*Methodologies to Account for Tagged Transactions*) below to account for import and export tagged transactions and shall apply it consistently for each of the following calculations:

1. the Market Flow calculation;
2. the Firm Flow Limit calculation;
3. the Firm Flow Entitlement calculation; and
4. the tagged transaction impact calculation which occurs in the IDC.

Market Flows represent the impacts of internal generation (including generators pseudo-tied into the market area and excluding generators pseudo-tied out of the market area) serving internal load (including load pseudo-tied into the market area and excluding load pseudo-tied out of the market area) and tagged grandfathered transactions within the market area. Market Flows shall not include the impacts from import tagged transaction(s) into and export tagged transaction(s) out of the market area where the impacts of the interchange transactions are accounted for by the IDC. A Market-Based Operating Entity shall utilize the IDC to calculate the impacts of import tagged transactions into and export tagged transactions out of the market area that are not captured in the Market Flow calculation. The impact of the EAR shall be included in the Market Flow calculation using the methodology selected in Section 4.1.1 (*Methodologies to Account for Tagged Transactions*); the related tags will be excluded in IDC. For an import EAR, load will be adjusted, and for an export EAR, generation will be adjusted, in accordance with the methodology selected in Section 4.1.1 (*Methodologies to Account for Tagged Transactions*).

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. Units outside of the market area that are pseudo-tied into the market to serve the market area's load will be included 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 (i.e., where pseudo-tie does not exist).

Additionally, there may be situations where the participation of a generator in the market that is not modeled as a pseudo-tie may be less than 100% (e.g., a unit jointly owned in which not all of the owners are participating in the market). This situation occurs when the generator output controlled by the non-participating parties is represented as interchange with a corresponding tag(s) and not as a pseudo-tie generator internal to each party's Control Area. Except for the generator output represented by qualifying interchange transactions from jointly owned units described in the following paragraph, such situations will be addressed by including the generator output in that Market-Based Operating Entity's Market Flow calculation with the amount of generator output not participating in the market being scaled down within the Market-Based Operating Entity's region or regions in accordance with one of the following three methodologies described and defined below in Section 4.1.1: the Marginal Zone Method, POR-POD Method, or Slice-of-System Method.

When a jointly owned unit, which is also listed as a Designated Network Resource for the Historic Firm Flow calculation, participates in more than one market, and the generator output from that unit between the two markets is represented as interchange with a corresponding tag(s) that is accounted for by the IDC and not as a pseudo-tie generator internal to each market's Control Area, its modeling in the Market Flow calculation will be aligned with that in the Historic Firm Flow calculation. The amount of generator output from that unit scheduled between the two markets will be treated as a unit specific export tagged transaction in the Market Flow calculation of the Market-Based Operating Entity where the generator is located and will be treated as a load-specific import tagged transaction in the Market Flow calculation of the other Market-Based Operating Entity.

- For exports out of one market area associated with the jointly owned unit(s), the generator output of jointly owned unit will be scaled down by an amount which is the lesser of the corresponding export tagged transaction(s) and unit ownership of an owner participating in other market area.

- For imports into the other market area associated with the jointly owned external unit(s), the Control Zone load or bus load(s) will be scaled down by an amount which is the lesser of the corresponding import tagged transaction(s) and unit ownership of an owner participating in the market area.

Import tagged transactions, export tagged transactions, and grandfathered tagged transactions within the market area, must be properly accounted for in the determination of Market Flows.

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 Directional "Market Flows" = ∑ (Directional "Market Flow" contribution of each unit in the Market-Based Operating Entity's area), grouped by impact direction

where,

"Market Flow" contribution of each unit in the Market-Based Operating Entity's area =

($GLDF_{Adj}$) (Adjusted Real-Time generator output)

and,

$GLDF_{Adj}$ is the Generator to Load Distribution Factor

Where the generator shift factor (GSF_{Adj}) uses Adjusted Real-Time generator output and the load shift factor (LSF_{Adj}) uses Adjusted Real-Time bus loads.

$GLDF_{Adj} = GSF_{Adj} - LSF_{Adj}$

Adjusted Real-Time generator output is the output of an individual generator as reported by the state estimator solution that has been adjusted for exports associated with joint ownership, if any, and then further adjusted for the remaining exports utilizing the chosen methodology in Section 4.1.1.

Adjusted Real-Time bus load is the sum of all bus loads in the market as reported by the state estimator solution that have been adjusted for imports associated with joint ownership, if any, and then further adjusted for the remaining imports utilizing the chosen methodology in Section 4.1.1.

The real-time and one-hour ahead projected "Market Flows" will be calculated on-line utilizing the Market-Based Operating Entity's state estimator model and solution. This is the same solution presently used to determine real-time market prices 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. Additionally off-line models may not reflect the impact of units such as wind generators. 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 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. Reciprocal Entities will coordinate models to ensure similar computations and analysis. Reciprocal Entities will each utilize real-time ICCP and ISN data for observable areas in each of their respective state estimator models and will utilize SDX data for areas outside the observable areas to ensure their models stay synchronized with each other and the EIDSN IDC.

4.1.1 Methodologies to Account for Tagged Transactions

A Market-Based Operating Entity shall choose one of the following methodologies to account for export and import tagged transactions in the Market Flow calculation utilized for market-to-market, and shall also use the same methodology to account for export and import tagged transactions in the Firm Flow Limit and Firm Flow Entitlement calculations, as well as calculated tag impacts by the IDC:

1. Point-of-receipt (POR) / point-of-delivery (POD) Method (POR-POD Method) - Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for based on the POR of the transmission service reservation, as the transmission service was originally sold, that is listed on the export tagged transaction by proportionally offsetting the MW output of all units (i) in the Market-Based Operating Entity's Control Area, (ii) pre-integration NERC-recognized Control Area(s), or (iii) sub-regions within its Control Area. Import tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for based on the POD of the transmission service reservation, as the transmission service was originally sold, that is listed on the export tagged transaction by proportionally offsetting the MW load of all load buses (i) in the Market Based Operating Entity's Control Area, (ii) pre-integration NERC-recognized Control Area(s), or (iii) sub-regions within the Control Area; or

2. Marginal Zone Method – Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by adjusting the MW output of the units in the Market-Based Operating Entity's Control Area, regions, or subregions within its Control Area by the total MW amount of all the Market-Based Operating Entity's export tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market using: (1) marginal zone participation factors, as defined and calculated in Appendix B (*Determination of Marginal Zone Participation Factors*); and (2) the anticipated availability of a generator to participate in the interchange of the marginal zone. Import tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by adjusting the MW load of the load buses in the Market-Based Operating Entity's Control Area, regions or subregions within the Control Area, by the total MW amount of all the Market-Based Operating Entity's import tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market using marginal zone participation factors, as defined and calculated in Appendix B (*Determination of Marginal Zone Participation Factors*); or

3. Slice of System Method – Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by proportionately adjusting the MW output of each of the units in the Market-Based Operating Entity's Control Area by the total MW amount of all the Market-Based Operating Entity's export tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market. Import tagged transactions, excluding tagged transactions associated with jointly owned

units participating in more than one market , shall be accounted by proportionately adjusting the MW load of each of the load buses in the Market-Based Operating Entity's Control Area by the total MW amount of all the Market-Based Operating Entity's import tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market.

Each Market-Based Operating Entity shall post and maintain a document on its public website that describes calculations and assumptions used in those calculations regarding the chosen methodology and its application to the treatment of import and export transactions to the calculation of Market Flows, Firm Flow Limits, and Firm Flow Entitlements, and tag impacts calculated by the IDC.

4.2 Firm Flow Determination

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

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

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

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

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

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

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

4.3 Determining the Firm Flow Limit

Given the Firm Flow determinations described in the previous section, Market-Based Operating Entities can assume them to be their Firm Flow Limits. These limits define the maximum value of the GTL flows that can be considered as firm in each direction on a particular Flowgate in the IDC, and the maximum value of the Market Flows that can be considered firm on a particular flowgate for market-to-market. Prior to real-time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Flows.

4.4 Firm Flow Limit Calculation Rules

The Firm Flow Limits for both 0% GTL flows and 5% GTL flows will be calculated for each Market-Based Operating Entity based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC but will include one set of impacts down to 0% and another set down to 5%. The down to 0% impacts will be used to determine Firm Flow Limits on 0% GTL flows. The down to 5% impacts will be used to determine Firm Flow Limits on 5% GTL flows. The following points form the basis for the calculation.

1. The generation-to-load calculation will be made on a Control Area basis. The impact of generation-to-load will be determined for Coordinated Flowgates.
2. The Flowgate impact will be determined based on individual generators serving aggregated CA load. Only generators that are Designated Network Resources for the CA load will be included in the calculation.
3. Forward Firm Flow Limits for 0% GTL flows will consider impacts in the additive direction down to 0%, and reverse Firm Flow Limits for 0% GTL flows will consider impacts in the counter flow direction down to 0%. Forward Firm Flow Limits for 5% GTL flows will be determined by subtracting impacts between 0% and 5% in the additive direction from the Forward Firm Flow Limit for 0% GTL flows. Reverse Firm Flow Limits for 5% GTL flows will be determined by subtracting the impacts between 0% and 5% in the counter-flow direction from the reverse Firm Flow Limit for 0% GTL flows. Flowgate Firm Flow Limits using a 5% threshold are reported to the IDC for it to assign the Firm and non-Firm GTL flows used in TLR curtailments for each Market-Based Operating Entity. Flowgate Firm Flow Limits using a 0% threshold are reported to the IDC for information purposes.
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 Transmission Service reservations and all Designated Network Resources that are in effect throughout the calculation period. Designated Network Resources are included in CA net interchange to the extent they are located outside the CA and have an OASIS reservation. The net interchange will either be positive (exports exceed imports) or negative (imports exceed exports).
8. If the net interchange is negative, the period load is reduced by the net interchange.
9. If the net interchange is positive, the period load is not adjusted for net interchange.
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 jointly owned units that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

5 Market-Based Operating Entity Congestion Management

Once there has been an establishment of the Firm Flow Limit that is possible given Firm Market Flow calculation, that data will be used in the operating environment in a manner that relates to real-time energy flows.

5.1 Calculating Market Flows

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all market-to-market Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation.

5.2 Quantify and Provide Data for Firm Flow Limits

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

- Firm Flow Limits for all Coordinated Flowgates in each direction

- Non-Firm Flow Limits for all Coordinated Flowgates in each direction

In real-time, any GTL flow in excess of the Firm Flow Limit will be reported as Non-Firm GTL flow (Priority 6-NN) (note that under reciprocal operations, some of this Non-Firm GTL flow may be quantified as Priority 2-NH).

These Limits will be provided for both current hour and next hour, and is used to communicate to Reliability Coordinators the maximum amount of flows to be considered firm and non-firm on the various Coordinated Flowgates in each direction. When the Firm Flow Limit forecast is calculated to be greater than the GTL flow for current hour or next hour, all GTL flow is firm.

Additionally, as frequently as once an hour, but no less frequently than once every three months, the Market-Based Operating Entity will submit to the Reliability Coordinator sets of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

5.3 Day-Ahead Operations Process

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

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

5.4 Real-time Operations Process-Operating Entity Capabilities

Operating Entities' 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, Reciprocal Entities will be continually working to ensure the models used in their calculation of Market Flow are kept up to date.

The Operating Entities submit various system measurements (load, generator outputs, control device status, etc.) from their state estimators and Unit Dispatch Systems (UDS) to the SDX in real-time. These measurements are used by the IDC to calculate both the actual and projected hour ahead flows (i.e., total GTL and tagged impact flows) on the Coordinated Flowgates. The IDC's calculations of system flows will utilize each Operating Entity's actual unit output, updated at least every 15 minutes on an established schedule.

5.5 Market-Based Operating Entity Real-time Actions

The Market-Based Operating Entity will upload the real-time and one-hour ahead projected Firm Flow Limits (7-FN) and Non-Firm Flow Limits (6-NN) on these Flowgates to the IDC every 15 minutes, as requested by the IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). Firm Flow Limits will be calculated, down to five percent and down to zero percent, and uploaded to the IDC. When the real-time actual flow exceeds the Flowgate limit and the Reliability Coordinator, who has responsibility for that Flowgate, has declared a TLR 3a or higher, the IDC will determine tag curtailments and GTL relief obligations using a tag impact and GTL impact of 5% or greater. The Market-Based Operating Entity will respond to the GTL relief obligation by redispatching their system. Note the Market-Based Operating Entity may provide relief through either: (1) a reduction of flows on the Flowgate in the direction required, or (2) an increase of reverse flows on the Flowgate.

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

The Reliability Coordinator calling the TLR will be able to see the relief provided on the Flowgate in both their EMS and in the IDC, as the IDC GTL calculation will reflect the redispatch of the Operating Entities with relief obligations through their real-time measurements submissions.

6 Reciprocal Operations

Reciprocal Coordination Agreements can be executed on a market-to-market basis, a market-to-non-market basis, and a non-market-to-non-market basis. While the congestion management portions of this document are intended to apply specifically to Market-Based Operating Entities, the agreement to allocate Flowgate capability is not dependent on an entity operating a centralized energy market. Rather, it simply requires that a set of Flowgates be defined upon which coordination shall occur and an agreement to perform such coordination.

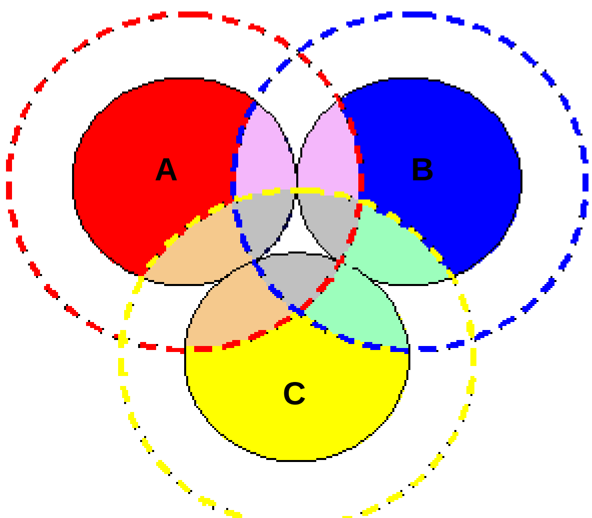
6.1 Reciprocal Coordinated Flowgates

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

6.2 The Relationship Between Coordinated Flowgates and Reciprocal Coordinated Flowgates

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

- It will meet the criteria for Coordinated Flowgate status for both the Reciprocal Entities,
- It will be under the functional control of one of the two Reciprocal Entities and
- Both Reciprocal Entities have executed Reciprocal Coordination Agreements either with each other or with a Third Party Reciprocal Entity.



As shown in the illustration above, Operating Entity A, Operating Entity B and Operating Entity C each have their own set of Coordinated Flowgates (represented by the blue, yellow and red dotted-line circles). Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's, Operating Entity B's or Operating Entity C's service territory (the gray area), they will be considered Reciprocal Coordinated Flowgates between all three entities. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's or Operating Entity B's service territory (the purple area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity A only. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity B's or Operating Entity C's service territory (the green area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity C only. Where those sets of

Coordinated Flowgates overlap AND they are in either Operating Entity A's or Operating Entity C's service territory (the orange area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity A and Operating Entity C only.

To the extent that entities other than Market-Based Operating Entities may enter into a Reciprocal Coordination Agreements, they may offer to coordinate on Flowgates that are Coordinated Flowgates (i.e., have passed one of the five tests defined within this document or otherwise been deemed to be a Coordinated Flowgate).

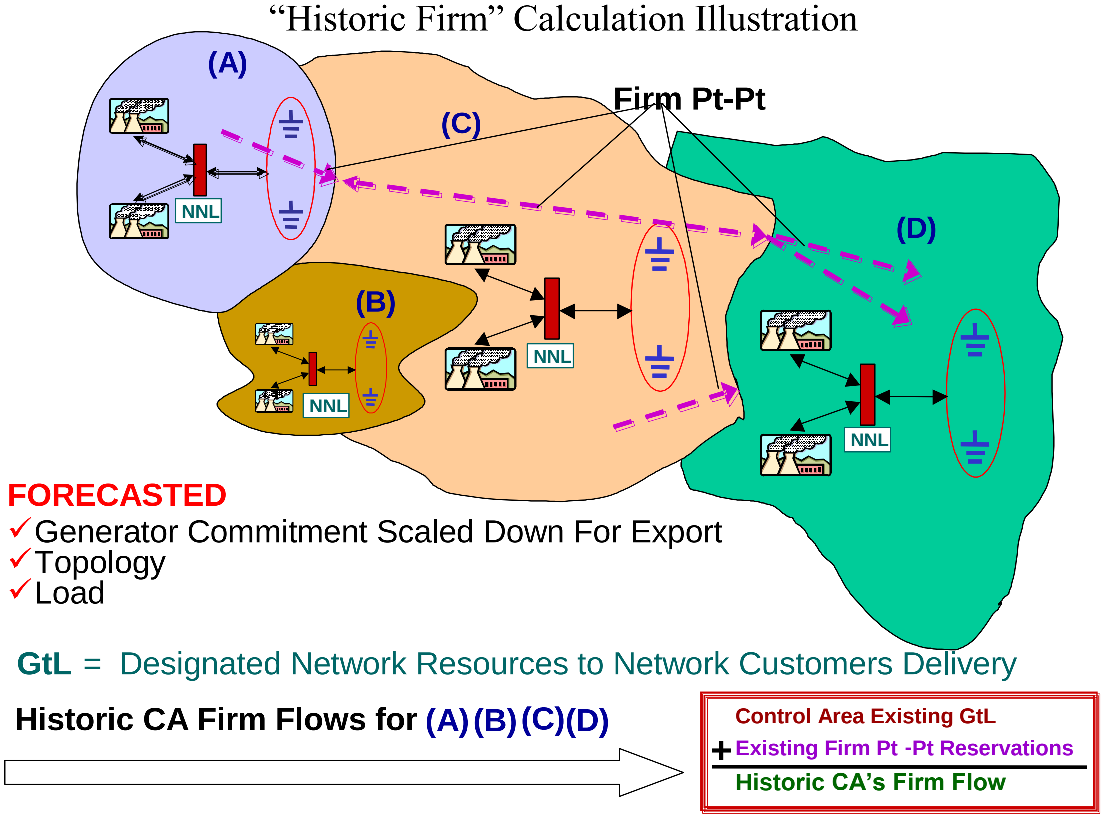
6.3 Coordination Process for Reciprocal Flowgates

The following process and timing will be used for coordinating the ATC/AFC calculations and Firm Flow Limit calculations/Allocations between Reciprocal Entities. Further, the process quantifies and limits Priority 6 – NN service on the Reciprocal Coordinated Flowgates, as well as determines priority 2-NH service. All Reciprocal Entities’ Firm Flow Limits will be calculated on the same basis.

6.4 Calculating Historic Firm Flows

As a starting point for identifying Allocations, an understanding must be developed of what Firm Flows would be in the historic Control Area structure. In other words, there must be a quantification of the Firm Flows that would have occurred if all Control Areas maintained their current configuration and continued to: (1) serve their native load with their Designated Network Resources, and (2) import and export energy at historical levels (based upon Firm Transmission Service reservations as of the Freeze Date, which is currently set as April 1, 2004. This flow is referred to as Historic Firm Flow.

“Historic Firm” Calculation Illustration



Reciprocal Entities will utilize the IDC Base Case model, or a mutually agreed upon alternative model as the reference base case for these calculations.

6.5 Recalculation of Initial Historic Firm Flow Values and Ratios

The Firm Transmission Service and Designated Network Resource to customer load defined by the Historic Firm Flow calculation will be updated in the recalculation of Historic Firm Flow utilizing any new Designated Network Resources, updated customer loads, and new transmission facilities. The original historic Control Areas will be retained for the recalculation of Historic Firm Flow. New Designated Network Resources will be included in the recalculation to the extent these new Designated Network Resources have been arranged for the exclusive use of load within the historic Control Areas and to the extent the total impact of all Designated Network Resources does not exceed the historic Control Area impact of Designated Network Resources as of a “Freeze Date” (defined as April 1, 2004). Any changes to Designated Network Resources and/or the transmission system that increase transmission capability will be assessed in accordance with the Reciprocal Entities AFC Coordination procedures prior to the increasing of Historic Firm Flow related to those systems.

The initial Historic Firm Flow calculated values and resulting Allocation ratios will be recalculated as seasonal cases are produced. This recalculation will utilize the same Firm Transmission Service reservations that were used in the initial Historic Firm Flow calculation. The same Firm Transmission Service reservations are used so that Market-Based Operating Entities that have their Firm Transmission Service internalized, grant fewer internal Firm Transmission Service reservations, or have their original Firm Transmission Service reservations end, because of their market operations, will retain at least the same level of Firm Transmission Service as in the initial Historic Firm Flow calculation. Therefore, the Firm Transmission Service component of the Historic Firm Flow will be frozen on the “Freeze Date” at the initially calculated level for both market and non-market entities.

Any new Control Areas that are added to the Firm Flow calculation process for any Reciprocal Entity, or another Operating Entity, will use Firm Transmission Service reservations from the initial Historic Firm Flow calculation date to establish their Firm Transmission Service component of the Historic Firm Flow.

As the recalculation for Historic Firm Flow is made for each time period, the higher of allocation value will be retained between the initial Historic Firm Flow calculation and the recalculation (See “Forward Coordination Process” Section 6.6, step 8.f). To the extent an Operating Entity has made commitments based on the higher of Allocation value, a recalculation does not reduce previously calculated Allocations.

6.6 Forward Coordination Processes

1. For each Reciprocal Coordinated Flowgate, a managing entity and an owning entity will be defined. The manager will be responsible for all calculations regarding that Flowgate; the owner will define the set of Firm Transmission Service reservations to be utilized when determining Firm Transmission Service impacts on that Flowgate.
2. Managing entities will calculate both Historic Firm Gen-to-Load Flow impacts and historic Firm Transmission Service impacts for all entities. These impacts will be used to define the Historic Ratio and the Allocation of transmission capability.
3. The managing entity will utilize the current IDC Base Case (or other mutually agreeable base case) to determine impacts. The case should be updated with the most current set of outage data for the time period being calculated.
4. Managing entities will calculate Allocations on the following schedule:

Allocation Run Type	Allocation Process Start	Range Allocated	Allocation Process Complete
April Seasonal Firm	Every April 1 at 8:00 EST	Twelve monthly values from October 1 of the current year through September 30 of the next year	April 1 at 12:00 EST
October Seasonal Firm	Every October 1 at 8:00 EST	Twelve monthly values from April 1 of next year through March 31 of the following year	October 1 at 12:00 EST
Monthly Firm	Every month on the second day of the month at 8:00 EST	Six monthly values for the next six successive months	2nd of the month at 12:00 EST
Weekly Firm	Every Monday at 8:00 EST	Seven daily values for the next Monday through Sunday	Monday at 12:00 EST
Two-Day Ahead Firm	Every Day at 17:00 EST	One daily value for the day after tomorrow	Current Day at 18:00 EST
Day Ahead Non-Firm	Every Day at 8:00 EST	Twenty-four hourly values for the next 24-hour period (Next Day HE1-HE24 EST)	Current Day at 9:00 EST

5. Historic Ratios are defined during the seasonal runs the first time an impact is calculated. For example, the 2004 April seasonal firm run would define the Historic Ratio for April 2005 – September 2005 (October through March would have been calculated during the 2003 October seasonal firm run). The Historic Ratio is based on the total impacts of the Reciprocal Entity on the Flowgate (Historic Firm Gen-to-Load Flows and historic Firm Transmission Service flows, down to 0%) relative to the total impacts of all other Reciprocal Entities' impacts on the Flowgate. For example, if Reciprocal Entity A had a 30 MW impact on the Flowgate and Reciprocal Entity B had a 70 MW impact on the Flowgate, the Historic Ratios would be 30% and 70%, respectively.
6. The same rules defined in the "Market-Based Operating Entity Congestion Management" Section 5 of this document for use in determining Firm Transmission Service impacts (NNL) shall apply when performing Allocations.
7. Additional rules to be used when considering Firm Transmission Service impacts are defined later within this section.
8. For each firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage:

   a. Retrieve the Flowgate limit
   b. Subtract the current Transmission Reliability Margin (TRM) value (may be zero)
   c. Subtract the sum of all historically determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%
   d. Accommodation of Capacity Benefit Margin (CBM).
      - If no capacity remains after step (c), entities' firm Allocation is limited to this amount (i.e., their Firm Flow impacts from impacts of 5% or greater), and the firm Allocation for the entity with functional control over the Flowgate is increased by the current CBM value (may be zero).
      - If capacity does remain after step (c), and the sum of all Reciprocal Entities' impacts below 5% plus CBM is less than the remaining capacity from step (c), that capacity is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5% up to the total amount of their Firm Flow impacts due to impacts less than 5%.
      - If there is not sufficient capacity for all impacts below 5% plus CBM to be accommodated, the current CBM value is subtracted from the remaining capacity from step (c), and granted to the entity with functional control over the Flowgate. Any capacity remaining is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5%.
   e. Any remaining capacity, after step (d) will be considered firm and allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5). If the remaining capacity allocated to the entity with functional control over the Flowgate meets or exceeds the current CBM value, no further effort is needed. If the remaining capacity is less than the CBM, capacity will first be reduced by the CBM, and the entity with functional control over the Flowgate will be granted the capacity needed to support the CBM. In addition each Reciprocal Entity (including the entity with

functional control over the Flowgate) will receive allocations determined as a pro-rata share of the remaining capacity (as described in Step 5).

f. Upon completion of the Allocation process, the managing entity will compare the current preliminary Allocation to the previous Allocations. For any given Flowgate, the larger of the Allocations will be considered the Allocation (i.e., an Allocation cannot decrease). Once all preliminary Allocations have been compared and the final Allocation determined, the managing entity will distribute the Allocations to the appropriate Reciprocal Entities. This Allocation will consist of the firm Gen-to-Load limit and a portion of capability that can be used either for Firm Transmission Service or additional firm Gen-to-Load service.

9. For the non-firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage. For each hour, the managing entity shall:

   a. Retrieve the Flowgate limit.
   b. Subtract the current TRM value (may be zero).
   c. Subtract the sum of all hourly historically determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%.
   d. Subtract the sum of all hourly historically-determined Firm Flow impacts for all Reciprocal Entities based on impacts less than 5%.
   e. Any remaining capacity will be allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5).
   f. The two-day ahead firm Allocation is subtracted from the total entity Allocation (from steps c, d, and e).
      - If the result is positive, this value will be equivalent to the Priority 6-NN Allocation/limit, and the Firm Flow Limit for 0% Market Flows will be the two-day ahead firm Allocation.
      - If the result is negative or zero, the Priority 6-NN Allocation will be calculated by subtracting the total entity Allocation (from steps c, d and e) from the two-day ahead firm Allocation. The Firm Flow Limit for 0% Market Flows will be the equivalent of the total entity allocation.
   g. Upon completion of the Allocation process, the managing entity will distribute the Allocations to the appropriate Reciprocal Entities. These Allocations will be considered non-firm network service.

When a Market-Based Operating Entity is uploading Firm Flow Limits to the IDC, they will be responsible for ensuring that any firm Allocations are properly accounted for. If firm Allocations are used to provide additional firm network service, they should be included in the Firm Flow Limit. If they are used to provide additional Firm Transmission Service, they should not be included in the Firm Flow Limit.

The Market-Based Operating Entities will maintain in real-time their Firm Transmission Service and Network Non-Designated service impacts, within their respective firm and Priority 6 total

Allocations. The Firm Transmission Service impacts will be based on schedules. The Operating Entities participating in the Coordinated Process for Reciprocal Flowgates will respect their allocations when granting Firm Transmission Service.

Using the derived firm Allocation value, the Market-Based Operating Entity may choose to enter this value as a Flowgate limit for the respective Flowgate. If entered as a Flowgate limit, the Day-Ahead unit commitment will not permit flows to exceed this value as it selects units for this commitment. Market-Based Operating Entities will use the Flowgate limit to restrict unit outage scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate.

As Reciprocal Entities gain more experience in this process, implement and enhance their systems to perform the Firm Flow calculations and Allocations, they may change the timing requirements for the Forward Coordination Process by mutual agreement.

6.6.1 Determining Firm Transmission Service Impacts

Firm impacts used in the Allocation process incorporate the Firm Transmission Service flows. Similar to the network service calculation described previously, to calculate each Firm Transmission Service transaction's impact on the Flowgate, the following process is utilized:

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 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 by direction will provide the directional Firm Transmission Service impact on the Flowgate.

Combining the directional Firm Transmission Service impacts with the directional NNL impacts will provide the directional Firm Flows on the Flowgate.

6.6.2 Rules for Considering Firm Transmission Service

1. Firm Transmission Service and Designated Network Resources that have an OASIS reservation are included in the calculation.

2. Reciprocal Entities will utilize a Freeze Date of April 1, 2004. Reciprocal Entities will utilize a reference year of June 1, 2004 through May 31, 2005 for determining the confirmed set of reservations that will be used in the Allocation process. The reference year is used such that reservation impacts in a given month in the reference year are used for each comparable month going forward in the Allocation process. For example, the Allocations for July 2004, July 2005, and July 2006 etc. will always use the July 2004 reservation impacts from the reference year. 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 Reciprocal Coordinated Flowgates owned by the party that sold the partial path service, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, and 0% of its impacts considered on other Reciprocal 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 will be considered Reciprocal Entities, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, which in this case are the same. Similar to the firm network service calculation, the Firm Transmission Service calculation:

    a. Will consider all reservations (including those with less than 5% impact).

    b. Will base response factors on the topology of the system for the period under consideration.

    c. In general, will not make a generation-to-load calculation where a reservation exists.

6.6.3 Limiting Firm Transmission Service

The Flowgate Allocations down to 0% will represent the share of total Flowgate capacity (STFC) that a particular entity has been allocated. This STFC represents the maximum total impact that entity is allowed to have on that Flowgate.

In order to coordinate with the existing AFC process, it is necessary that this number be converted to an available STFC (ASTFC) which represents how much Flowgate capability remains available on that Flowgate for use as Transmission Service. In order to accomplish this, the entity receiving STFC will do the following:

Step	Example
1.) Start with the STFC	100
2.) Add all forward Gen to Load impacts (down to 0%) and all Reverse Gen to Load impacts (down to 0%) to obtain the Net Gen to Load impacts. The Gen to Load impacts should be based on the *best estimate* of firm Gen-to-Load Flow for the time period being evaluated.	42 + (-20) = 22
3.) Subtract the net Gen to Load impacts from the STFC	100 – 22 = 78
4.) Subtract the CBM to produce an interim STFC	78 – 0 = 78
5.) Determine the Transmission Service impacts of service that has been sold. By default, it should be assumed that 100% of forward service and 15% of counterflowing service will be scheduled and used. However, if Flowgate "owner" uses different percentages in their AFC calculation and the Flowgate manager's calculation engine support it, percentages other than 100% and 15% may be used. Add all forward Transmission Service impacts (down to 0%) and all appropriate reverse Transmission Service impacts (down to 0%) to obtain the weighted net Transmission Service impacts. The	58 + (0.15 (-45)) = 58 + (-6.75) ≈ 58 + (-7) = 51

Transmission Service impacts should be based on the *current* set of reservations in effect for the time period being evaluated (*not* the historic reservation set)	
6.) Subtract the weighted net Transmission Service impacts from the Interim STFC. The result is the ASTFC	78 – 51 = 27

The ASTFC values for Reciprocal Coordinated Flowgates will be posted on OASIS along with the Allocation results. This ASTFC can then be compared with the AFC calculated through traditional means when evaluating firm requests made on OASIS.

If the AFC value is LOWER than the ASTFC value, the AFC value should be utilized for the purpose of approving/denying service. In this case, while the Allocation process might indicate that the entity has rights to a particular Flowgate through the Allocation process, current conditions on that Flowgate indicate that selling those rights would result in overselling of the Flowgate, introducing a reliability problem.

If the AFC value is HIGHER than the ASTFC value, the ASTFC value should be utilized for the purpose of approving/denying service. In this case, while the AFC process might indicate that the entity can sell more service than the Allocation might indicate, the entity is bound to not sell beyond their Allocation.

If a Reciprocal Entity uses all of its firm Allocation and desires to obtain additional capacity from another Reciprocal Entity who has remaining capacity, that additional capacity may be obtained using the procedures documented below.

6.7 Sharing or Transferring Unused Allocations

Reciprocal Entities shall use the following process for the sharing or transferring of unused Allocations down to 0% between each other.

6.7.1 General Principles

This process includes the following general principles in the treatment of unused Allocations.

1. A desire to fully utilize the Reciprocal Entities' Allocations such that in real-time, an unused Allocation by Reciprocal Entities is caused by a lack of commercial need for the Allocation by Reciprocal Entities and not by restrictions on the use of the Allocation.

2. For short-term requests (less than one year) where the lack of an Allocation could otherwise result in the denial of Transmission Service requests, there should be a mechanism to share or acquire a remaining Allocation on a non-permanent basis for the duration of the short-term transmission service requests. The short-term Allocation transfers would revert back to the Reciprocal Entity with the original Allocation after the short term request expires.

3. For long-term requests (one year or longer) where the lack of an Allocation could otherwise cause the construction of new facilities, there should be a mechanism to acquire a remaining Allocation such that new facilities are built only because they are needed by the system to support the transaction and not because of the Allocation split between Reciprocal Entities. Long-term Allocation transfers would apply to the original time period of the request including any roll-over rights that are granted for such requests.

4. Due to limitations on the frequency of transferring updated Allocation values and AFC's between the Reciprocal Entities, the Reciprocal Entities will utilize buffers to reduce the risk of overselling the same service, and to set aside a portion of the unused Allocation for the owner of the unused Allocation to accommodate any request that they may receive. The buffer will be reduced on a Flowgate based upon factors such as the rating of the Flowgate and operational experience, with the goal to maximize the use of the unused Allocation. The rationale for reducing the buffer is that potentially significant amounts of Transmission Service (up to many times the buffer amount) may be denied otherwise by the non-owner of the unused Allocation.

6.7.2 Provisions for Sharing or Transferring of Unused Allocations

1. Based upon the proposed infrastructure for Allocation calculations, daily Allocations are available for 7 days into the future and Weekly and Monthly Allocations are available up to 18 months into the future. Sharing and transferring of unused Allocations will be limited to the granularity of the Allocation calculations.

2. The Reciprocal Entities will share or transfer their unused firm Allocations during the time periods up until day ahead with the goal to fully utilize the Allocations.

3. This sharing or transfer of the unused Allocation will occur automatically for short-term Transmission Service requests, and manually for long-term (one year or greater) Transmission Service requests. The Reciprocal Entity that has been requested to transfer unused Allocations to the other Reciprocal Entity for a long-term request shall respond within 5 business days of receipt of the transfer request.

4. The Reciprocal Entities will post information available to the other Reciprocal Entity on all requests granted that shared or acquired the other Reciprocal Entity's Allocation on a daily basis for review.

5. Sharing an Unused Allocation During the Near-Term

   The Reciprocal Entities will share their Allocations during the near-term (the first 7 days up until day ahead or a mutually agreed upon timeframe) with the goal to fully utilize the Allocations once in real-time through an automated process.

   This sharing of the unused Allocation during the near-term will occur such that an unused Allocation that has not already been committed for use by either Firm Transmission Service or for market service will be made available to the other Reciprocal Entities for their use to accommodate Firm Transmission Service requests submitted on OASIS.

   Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

   a. A sharing of Allocation can occur.
   b. The sharing shall be done on a comparable basis for the market and non-market entities.
   c. The sharing is not related to projected Firm Flow Limits absent new DNRs or Transmission Service submitted on OASIS.
   d. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs. If the details

of this process cannot be agreed upon, there shall be no sharing of the unused Allocations during the near-term.

e. A buffer will limit the amount of Allocation that can be shared for short-term requests during automated processing of the Allocation sharing process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the buffer shall not be allowed to be less than a certain MW value. For example, a 25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity's unused Allocation while making sure that the other entity's unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specific provisions of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a sharing of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will share the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

   For the sharing of unused Allocations in the near-term, the Allocations are <u>not</u> changed and should congestion occur, the IDC obligations for the giving Reciprocal Entity will be in accordance with its original Allocation. The receiving Reciprocal Entity will not be required to retract or annul any service previously granted due to the sharing of Allocations.

6. Acquiring an Unused Allocation Beyond the Near Term

When a Reciprocal Entity does not have sufficient Allocation on a Flowgate to approve a firm point-to-point or network service request made on OASIS and evaluated via automated request evaluation tools and the other Reciprocal Entity has a remaining Allocation, the deficient Reciprocal Entity will be able to acquire an Allocation from the Reciprocal Entity with the remaining Allocation. This Allocation must not already be committed for other appropriate uses, as agreed to by the Reciprocal Entities, and sufficient AFC must remain on the Flowgate, or will be created, to accommodate the request. Such cases will be handled via automated processes.

Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

a. A transfer of Allocation can occur.
b. The transfer shall be done on a comparable basis for the market and non-market entities.
c. The transfer is not related to projected Firm Flow Limit absent new DNRs or Firm Transmission Service submitted on OASIS.

d. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs   If the details of this process cannot be agreed upon, there shall be no transfer of the Allocation for the time period beyond the near term.

A buffer will limit the amount of Allocation that can be acquired for these requests during automated processing of the Allocation transfer process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the buffer shall not be allowed to be less than a certain MW value. For example, a 25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity's unused Allocation while making sure that the other entity's unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specifics of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a transferring of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will transfer the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

The determination of whether the remaining Allocation has already been committed will be established based on OASIS queue time. All requests received prior to the queue time will be considered prior commitments to the remaining Allocation, while such requests are in a pending state (e.g. study status) or confirmed state. Requests received after the queue time will be ignored when determining whether remaining capacity has already been committed.

In the event that prior-queued requests are still in a pending state (i.e. not yet confirmed), the Reciprocal Entity requesting a transfer of unused Allocations may await the resolution of any prior-queued requests in the other Reciprocal Entity's OASIS queue before relinquishing its ability to request an Allocation transfer.

For the transfer of unused Allocations, the Reciprocal Entity's Allocations will be changed to reflect the Allocation transfer at the time the Allocation transfer request is processed. To the extent the request is not ultimately confirmed, the Allocation will revert back to the original Reciprocal Entity with the remaining Allocation. For yearly requests, the transfer of the Allocation applies to the original time period of the request including any roll-overs that are granted.

6.8 The Application of Firm Flow Limits in the IDC

In addition to the responsibilities described earlier in "Market-Based Operating Entity Congestion Management" Section 5 of this document, Market-Based Operating Entities will have an additional obligation, on Reciprocal Coordinated Flowgates, to further quantify their Non-Firm GTL flows into two (2) separate priorities in the IDC: Non-Firm Network (6-NN), and Non-Firm Hourly (2-NH). Within the IDC, the priorities will be determined as follows:

1. If the GTL flow exceeds the sum of the Firm Flow Limit and the 6-NN Allocation, then:
   2-NH = GTL flow – (Firm Flow Limit + 6-NN Allocation)
   6-NN = 6-NN Allocation
   7-FN = Firm Flow Limit
2. If the GTL flow exceeds the Firm Flow Limit but is less than the 6-NN Allocation, then:
   2-NH = 0
   6-NN = GTL flow – Firm Flow Limit
   7-FN = Firm Flow Limit

3. If the GTL flow does not exceed the Firm Flow Limit, then
   2-NH = 0
   6-NN = 0
   7-FN = GTL flow
4. If the tag associated with EAR is converted to Market Flow and excluded by the IDC, the Market Flow shall have a priority that is no higher than it would have been if the tag was not excluded by IDC. This provision aims to keep the application of these tags consistent between the Market Flow used in market-to-market and the GTL calculation performed by the IDC and used in TLR.

All other aspects of this data remain identical to those described in "Market-Based Operating Entity Congestion Management" Section 5.

6.9 Real-time Operations Process for Market-Based Operating Entities

6.9.1 Market-Based Operating Entity Capabilities

Capabilities remain as described in “Market-Based Operating Entity Congestion Management” Section 5.

6.9.2 Market-Based Operating Entity Real-Time Actions

Procedures remain as described in "Market-Based Operating Entity Congestion Management" Section 5. However, as described above, additional information regarding the firmness of those Non-Firm GTL flows will be communicated as well. A portion will be reported as 6-NN, while the remainder will be reported as 2-NH. This will provide additional ability for the IDC to curtail portions of the Non-Firm GTL flows earlier in the TLR process.

6.10 Requirements to Combine Allocations with Non-Reciprocal Entity

The following requirements must be satisfied for a Combining Party to incorporate a Non-Reciprocal Entity's load and the associated generation serving that load into the Reciprocal Entity's Allocation calculations:

1. The Non-Reciprocal Entity's load and associated generation serving that load participates in the market of the Combining Party pursuant to a FERC-accepted agreement(s).
2. The Non-Reciprocal Entity has not placed its transmission facilities under the Open Access Transmission Tariff of the Combining Party, nor has the Non-Reciprocal Entity executed a transmission owner agreement or membership agreement, or equivalent thereof, of the Combining Party.
3. The Non-Reciprocal Entity is wholly embedded (i.e., the load and associated generation serving that load are included in Allocations, Market Flows, and IDC GTL calculations) into the Combining Party's Control Area footprint in accordance with the CMP.
4. The Combining Party must treat the Non-Reciprocal Entity's impacts in the IDC, Market Flow, Firm Flow Limit, and Firm Flow Entitlement calculations consistently as the Combining Party does its own impacts in accordance with this CMP. The Non-Reciprocal Entity's load and associated generation serving that load otherwise needs to be eligible for inclusion in firm Allocations, Firm Flow Limit, and Firm Flow Entitlement under the terms of this CMP.
5. Any transmission facilities owned by the Non-Reciprocal Entity must be treated comparably to the transmission facilities of other Reciprocal Entities consistent with the terms of the CMP.
6. The Combining Party must provide notice to the other Reciprocal Entities of its plans to combine allocations within sixty (60) calendar days of making a filing at the FERC that would result in a Non-Reciprocal Entity's load and associated generation serving that load being combined with the Combining Party or upon combining Allocations (whichever occurs first). Even though a situation in which a Combining Party has proposed to combine Allocations with a Non-Reciprocal Entity may satisfy requirement numbers 1 through 5 of this list, this does not preclude other Reciprocal Entities from raising any objection pursuant to the dispute resolution process of a joint operating agreement or by filing a Section 206 complaint with the FERC if the proposed combination of Allocations would be inconsistent with this CMP or produces a result that is unjust and unreasonable.

7 Appendices

Appendix A - Glossary

Agreement – Agreement shall mean this Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., as amended from time to time, including all attachments, appendices, and schedules.

Allocation – A calculated share of capability on a Reciprocal Coordinated Flowgate to be used by Reciprocal Entities when coordinating AFC, transmission sales, and dispatch of generation resources.

Available Flowgate Capability (AFC) – The applicable rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

AFC Flowgate – A Flowgate for which an entity calculates AFC's.

Combining Party – Combining Party shall mean a Reciprocal Entity that is incorporating the load and associated generation serving that load from a Non-Reciprocal Entity into the Reciprocal Entity's Allocations pursuant to Section 6.10 of this CMP.

Control Area – Shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

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 (CF) – Shall mean a Flowgate impacted by an Operating Entity as determined by one of the five studies detailed in Section 3 of this document. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of this document (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

Designated Network Resource – A resource that has been identified as a designated network resource pursuant to a transmission provider's Open Access Transmission Tariff.

EIDSN – Eastern Interconnection Data Sharing Network.

External Asynchronous Resource[1] (EAR) – A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

Firm Flow – The estimated impacts of Firm Transmission Service on a particular Coordinated or Reciprocal Coordinated Flowgate.

Firm Flow Limit – The maximum value of Firm Flows an entity can have on a Coordinated or Reciprocal Coordinated Flowgate, based on procedures defined in Sections 4 and 5 of this document.

Firm Market Flow – The portion of Market Flow on a Coordinated or Reciprocal Coordinated Flowgate related to contributions from the native load serving aspects of the dispatch (constrained as appropriate by the Firm Flow Limit).

Firm Transmission Service – The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption or similar quality service offered by transmission providers by contract that do not require the filing of a rate schedule. Firm Transmission Service only includes firm point-to-point service, network designated transmission service and grandfather agreements deemed firm by the transmission provider as posted on OASIS.

Flowgate – A representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system.

Freeze Date – The cutoff date chosen by Reciprocal Entities to be used in the calculation of Historic Firm Flows.

Generation-to-Load (GTL) – The calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an Operating Entity's Control Area, as specified in NAESB BPS WEQ-008 starting version 3.3.

Generator Priority Schedules (GPS) – A schedule that indicates the Transmission Service curtailment priority of the generator output, as specified in NAESB BPS WEQ-008-9.1.3.

Generator Shift Factor – A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

Historic Firm Flow – The estimated total impact an entity has on a Reciprocal Coordinated Flowgate when considering the impacts of (1) its historic Designated Network Resources serving native load, and (2) imports and exports, based on Firm Transmission Service reservations that meet the "Freeze Date" criteria.

[1] External Asynchronous Resource is specific to the MISO tariff , MISO, FERC Electric Tariff, Module A, § 1.E "External Asynchronous Resource" (33.0.0).

Historic Firm Gen-to-Load Flow – The flow associated with the native load serving aspects of dispatch that would have occurred if all Control Areas maintained their current configuration and continued to serve their native load with their generation.

Historic Ratio – The ratio of Historic Firm Flow of one Reciprocal Entity compared to the Historic Firm Flow of all Reciprocal Entities on a specific Reciprocal Coordinated Flowgate.

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.

Load Shift Factor – A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

Locational Marginal Pricing (LMP) – The processes related to the determination of the LMP, which is the market clearing price for energy at a given location in a Market-Based Operating Entity's market area.

Market Flows – The calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity's market.

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

Network and Native Load (NNL) – The impact of generation resources serving internal system load, based on generation the network customer designates for Network Integration Transmission Service (NITS). NNL is also referred to as Gen to Load.

Non-Firm Market Flow – That portion of Market Flow related to a Market-Based Operating Entity's market operations in excess of that entity's Firm Market Flow.

Non-Reciprocal Entity – Non-Reciprocal Entity shall mean an Operating Entity that is not a Reciprocal Entity.

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.

Parallel Flow Visualization (PFV) – Conceptual ideas captured in NAESB BPS WEQ-008 starting with version 3.3.

Party or Parties – Party or Parties refers to each party to this Agreement or both, as applicable.

Reciprocal Coordination Agreement – An agreement between Operating Entities to implement the reciprocal coordination procedures defined in the CMP.

Reciprocal Coordinated Flowgate (RCF) – A Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. An RCF is:

1. A CF that is (a) (i) within the operational control of Reciprocal Entity or (ii) may be subject to the supervision of Reciprocal Entity as Reliability Coordinator, and (b) affected by the transmission of energy by two or more Parties; or

2. A CF that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to CMP reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or

3. A CF that is designated by agreement of both Parties as an RCF.

Reciprocal Entity – An entity that coordinates the future-looking management of Flowgate capacity in accordance with a Reciprocal Coordination Agreement as developed under Section 6 of this document, or a congestion management process approved by the Federal Energy Regulatory Commission; provided such congestion management process is identical or substantially similar to this CMP.

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

Tag Secondary Network Transmission Service Method (TSNT) – A method for determining the Transmission Service curtailment priority of the Secondary Network Transmission Service using e-Tags, as specified in NAESB BPS WEQ-008-1.9.2.

Third Party – Third Party refers to any entity other than a Party to this Agreement.

Tie Line – Tie Line shall mean a circuit connecting two Control Areas.

Transfer Distribution Factor – The portion of an interchange transaction, typically expressed in per unit, flowing across a Flowgate.

Transmission Service – Services provided to the transmission customer by the transmission service provider to move energy from a point of receipt to a point of delivery.

Appendix B – Determination of Marginal Zone Participation Factors

In order for the IDC to properly account for tagged transactions into and out of the market area, a Market-Based Operating Entity using the Marginal Zone methodology will need to provide participation factors representing the facilities contributing to the tagged transactions. The facility or facilities contributing to each export tagged transaction is the source of the export tagged transaction. The facility or facilities contributing to each import tagged transaction is the sink of the import tagged transaction.

The Market-Based Operating Entity will be required to define a set of zones that can be aggregated into a common distribution factor that is representative of the market area. This information must be shared and coordinated with the IDC. Following this step, the Market-Based Operating Entity must then send to the IDC participation factors for those zones. These participation factors represent the percentages of how these zones are providing marginal megawatts as a result of dispatch of resources in market operations to serve transactions. Data sets for each external source/sink are required, which correspond to:

- An IMPORT data set, which indicates the participation of facilities accommodating the energy imported into the market area, and

- An EXPORT data set, which indicates the participation of facilities accommodating the energy exported out of the market area.

The methodology used by the Market-Based Operating Entity to determine the Marginal Zone participating factors will be determined through collaboration of the Market-Based Operating Entity with the IDC working group.

Participation Factor Calculation

The Market-Based Operating Entity will use the real-time system conditions to calculate the marginal zone participation factors, which reflect the impacts of tagged transactions. These will establish, for imports and exports, a set of participation factors that, when summed, will equal 100 percent.

Appendix C – Flowgate Determination Process

This section is has been added to clarify:

- How initial Flowgates are identified (Figure C-1, Table C-1)
  - Process for Flowgates in the Coordinated Flowgate list
  - Process for Flowgates in the Reciprocal Coordinated Flowgate list
  - Process for Flowgates in the AFC List
- How Flowgates will be added (Figure C-2, Table C-2)
- How often Flowgates are changed (Figure C-2, Table C-2)

Figure C -1
Determine AFC Flowgates,
Coordinated Flowgates, and Reciprocal
Coordinated Flowgates

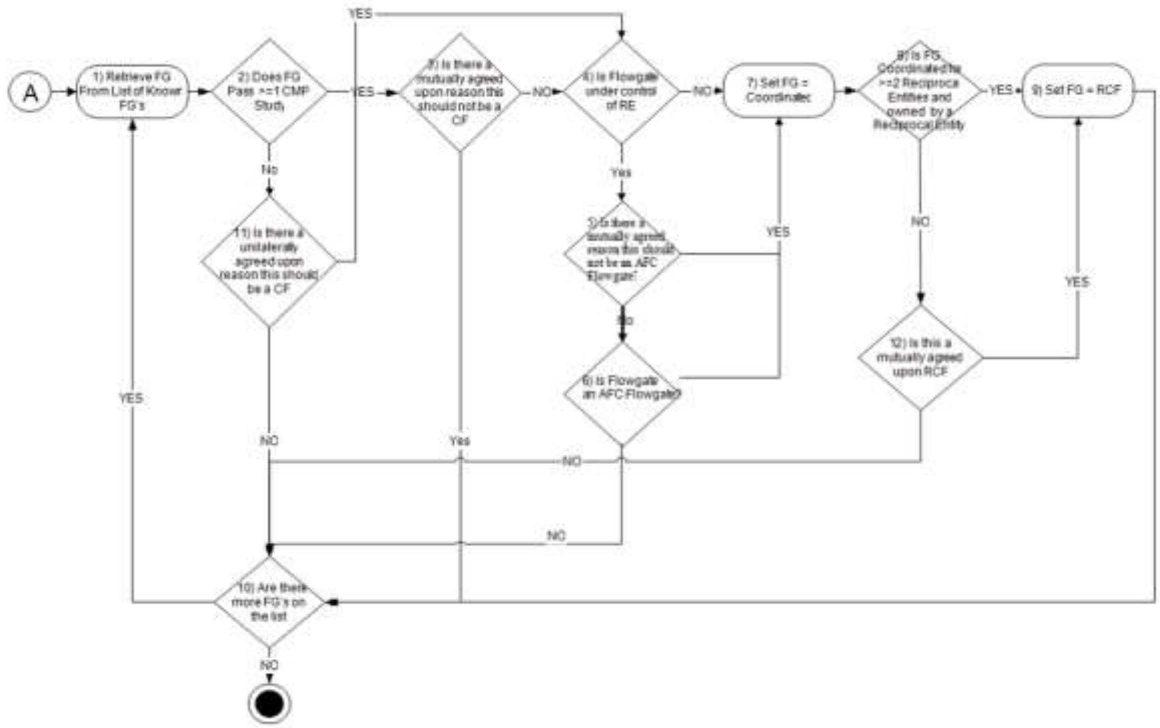


Table C-1

Step	Activity	Requirements	Detailed Description	Additional Documentation
1	Retrieve FG From List Of Known FG's	Retrieve FG from AFC list of FGs, NERC Book of FGs, and any other list of FGs.	• Retrieve the FG from the list of FGs. If a Reciprocal Entity wants us to consider a temporary FG it would go through the same process.	
2	Determine if FG passes >= 1 CMP Study	The decision determines if the FG passes at least one of the five CMP studies	• If the FG passes any of the studies, determine if there is mutually agreed upon reason why this should not be a coordinated FG. • If the FG does not pass any of the studies, it will be determined if there is a unilaterally decided reason for inclusion as a CF.	See Impacted Flowgate Determination - Section 3
3	Is There a Mutually Agreed Upon Reason This Should Not Be A Coordinated Flowgate	Determine if there is a mutually agreed reason, despite passing one of the five tests, why this FG should not be considered Coordinated.	• If there is no mutually agreed reason why this FG should not be considered coordinated, test whether FG is under control of a Reciprocal Entity. • If there is a mutually agreed reason why this FG should not be considered coordinated, record the reason proceed to Step 10.	
4	Is the Flowgate under control of a Reciprocal Entity	If the Flowgate is under the control of a non-reciprocal entity and the Flowgate passes one of the five tests it will be treated as a Coordinated Flowgate.	• If the Flowgate is not under control of a Reciprocal Entity proceed to Step 7. • If the Flowgate is under control of a Reciprocal Entity Proceed to Step 5.	

Step	Activity	Requirements	Detailed Description	Additional Documentation
5	Is there a mutually agreed reason this should not be AFC Flowgate?	Determine if there is a mutually agreed reason, despite qualifying as a Coordinated Flowgate, why this Coordinated Flowgate is not included in the AFC process.	• If there is a mutually agreed reason to not include the Coordinated Flowgate in the AFC process proceed to Step 7. • Otherwise proceed to Step 6	
6	Is Flowgate an AFC Flowgate	A check is done to determine if the Flowgate controlled by a Reciprocal Entity is in its AFC process.	• If the Flowgate is in the AFC process or in the process of being added to the AFC process proceed to Step 7. • Otherwise proceed to Step 10.	
7	Set FG = Coordinated	The FG would be coordinated for the entity.	• The FG would be considered a CF.	
8	Is FG Coordinated for >= 2 Reciprocal Entities and "owned" by a Reciprocal Entity	Determine whether the FG is coordinated for two or more Reciprocal Entities	• If the FG is coordinated for two or more Reciprocal Entities and it is "owned" by one of the entities, it will be added to the CMP process as a reciprocal coordinated FG. • If it is not coordinated for two or more Reciprocal Entities and "owned" by one of the entities, determine if it is a mutually agreed upon RCF.	CM Process - Section 6
9	Set FG = RCF	Set the Flowgate equal to a Reciprocal Coordinated Flowgate.	• Set the Flowgate equal to a Reciprocal Coordinated Flowgate. • Proceed to Step 10.	

Step	Activity	Requirements	Detailed Description	Additional Documentation
10	Are there more FGs on the list?	Determine if there are any more FGs on the list that need to go through the CMP determination process.	• If there are no more FGs that need to go through the determination process, the process ends. • If there are more FGs that need to go through the determination process, retrieve the next one. • Proceed to Step 1 if another FG requires evaluation. • Otherwise, the process ends.	
11	Is There a Unilateral Decision This Should Be A Coordinated FG	This decision determines if an entity wants to make this a Coordinated FG for a reason other than the five tests.	• If an entity decides to make this a coordinated FG, proceed to Step 4. • Otherwise, proceed to Step 10.	
12	Is This a Mutually Agreed Upon RCF	Determine if there is a mutually agreed reason this should be considered a Reciprocal Coordinated Flowgate.	• If there is no mutually agreed reason this should be considered an RCF, leave it as coordinated and check for more FGs. • If there is a mutually agreed reason this should be considered an RCF, mark it as such. • If Reciprocal Entities decide to make the Flowgate Reciprocal proceed to Step 9. • Otherwise, proceed to Step 10.	

Figure C-2
Flowgate Review and Customer
Flowgate Request

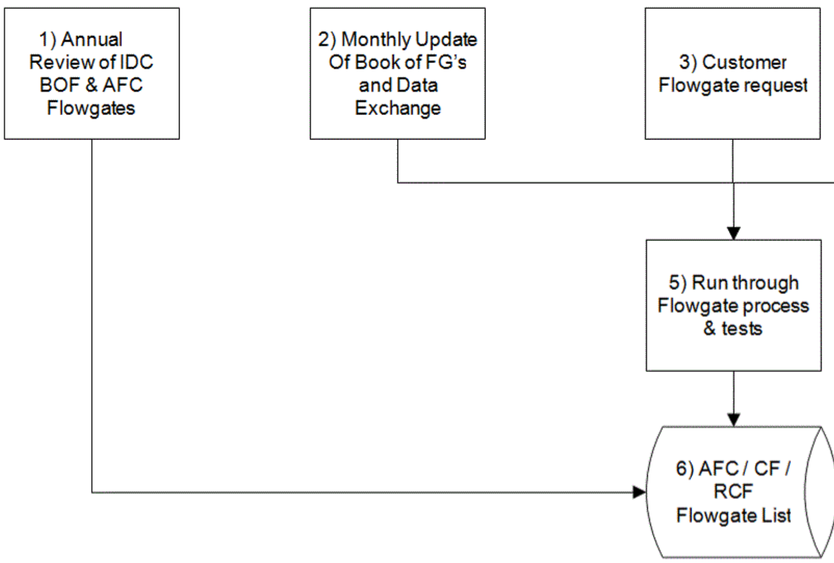


Table C-2

Steps	Activity	Requirements	Detailed Description	Additional Documentation
1	Annual Review of the BOFs and AFC FGs	A review will be performed annually or more often as requested by Reciprocal Entities (CMPWG). Retrieve the FG from the list of FGs for the entity running the process. Study 1 in section 3.2.1 of the CMP is not required for this annual review	• Except for Study 1 in section 3.2.1 of the CMP, the FGs will be run through the process summarized in figure C-1.	
2	Customer FG Requests	Any customer FG requests will also be subject to the tests and process above.	• Any customer FG requests will be run through the process summarized in figure C-1.	
3	Temporary Flowgate added by Reciprocal Entity	Any temporary Flowgate added by a Reciprocal Entity will also be subject to the tests and processes in Step 5.	• Any temporary Flowgates added by a Reciprocal Entity will be run through the process summarized in figure C-1	
4	Run Through FG Process and Tests	Run through FG Determination Process, figure C-1	• Any FGs being reviewed or added will be run through the process summarized in figure C-1.	
5	AFC/CF/RCF List	Any FG additions or modifications would need to be committed to the repository of FGs and their qualifications.	• Any FG additions or modifications would need to be committed to the repository of FGs, along with their qualifications.	

Appendix D - Training

The concepts in these proposals should not have a significant impact upon system operators beyond the operators of the Operating Entity. The reason that this impact rests upon the Operating Entities is that the Operating Entities Operators will need to be trained to monitor and respond to the external Flowgates.

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

1. The ability to take projected net system flows between an Operating Entity's 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 another RC Operator when the RC System Operator has a temporary Flowgate that they believe requires the implementation of the “Flowgate on the Fly” process.

Appendix E - Reserved

Appendix F – FERC Dispute Resolution

RCF Dispute Resolution

If a Party has followed all processes in the disputed Flowgate process outlined in section 3.2 and is dissatisfied with the ORS resolution of the Flowgate dispute, the Party may refer the dispute to FERC's Dispute Resolution Service for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

Allocation Adjustment for New Transmission Dispute Resolution

If a Party has followed all processes in the Allocation Adjustment Peer Review process outlined in Appendix G and is dissatisfied with the resolution of the CMPC, the Party may refer the dispute to FERC's Dispute Resolution Service for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

Appendix G - Allocation Adjustment for New Transmission Facilities and/or Designated Network Resources

1. Guiding Principles

The following guiding principles will be used in determining the allocation adjustments for New Transmission Facilities and/or Designated Network Resources.

- Principle 1 (Non-builder held harmless) - To the extent possible, the non-building entity will receive the same overall impacts in its allocations.
- Principle 2 (Builder receives benefits) - To the extent possible, the building entity will receive any benefit to the transmission system that result from the system upgrade.

To the extent these two principles conflict, the Non-Builder Held Harmless Principle will have priority over the Builder Receives Benefit Principle.

2. New Transmission Facilities that Do Not Involve New DNR or New Firm Transmission Service

To the extent a new transmission facility causes a significant decrease in flow on a Reciprocal Coordinated Flowgate the change in the allocation will be assigned to the Reciprocal Entity with functional control of the new transmission facility. Otherwise, the normal allocation procedures will be followed and no allocation adjustments for new transmission facilities will be made.

Significant impact is defined as a 3% change in flow that occurs to an OTDF Flowgate and a 5% change in flow that occurs to a PTDF Flowgate with the addition of the new facility. The 3% and 5% are measured as a percentage of the Flowgate TTC (sometimes called Total Flowgate Capability (TFC)).

The allocation adjustment will be assigned to the Reciprocal Entity with functional control of the new transmission facility. Both the original allocation and the allocation adjustment are assigned to the Reciprocal Entities. To the extent a group of transmission owners installs a new facility that includes multiple Reciprocal Entities and the new transmission facility results in a change in transfer capability on one or more RCFs, these Reciprocal Entities will work in collaboration to determine appropriate adjustments to each Reciprocal Entity's allocation on all significantly impacted RCFs.

An analysis will be performed both with and without the new facility to determine whether there is a significant impact on one or more RCFs. The analysis and any subsequent allocation adjustments will coincide with the expected in-service date of the new facility. The inclusion of the new transmission facility in such an analysis is dependent on having a commitment that the new facility has or is expected to receive all of the appropriate approvals and will be installed on the date indicated.

In order to qualify for an allocation adjustment, the new transmission facility must not only create a significant change in flows, it must also be a significant change to the transmission system (i.e. a new line or transformer that creates a significant change to flows on one or more RCFs). The addition of a new generator without transmission additions (other than the generation interconnection) is not covered by this process for new transmission facility additions. A change in the rating of an RCF may qualify as a significant change to the transmission system and be eligible to receive an allocation adjustment even though it does not result in a change in flows.

For stability limited Flowgates, a new generator, reactive device or change to a remedial action scheme may contribute to a change in the transfer limitation of stability limited Flowgates. Where this occurs and the addition is being made for the specific purpose of changing the transfer limitation of stability limited Flowgates, an allocation adjustment will be provided to the Reciprocal Entity responsible for the new generator, reactive device or change to a remedial action scheme. By receiving an allocation adjustment, this new generator, reactive device or change to a remedial action scheme will not also be included in the historical usage calculation to avoid double-counting of the impacts.

Not all new transmission facilities that significantly impact RCFs involve a change in flows. A new facility may be added that changes the rating of an RCF but has minimal impact on the flow (i.e. reconductoring, replacing a wave trap (WT) or current transformer (CT), replacing a transformer). In this case, each Reciprocal Entity's historical usage flow will remain constant but the rating of the Flowgate will either increase or decrease. The Reciprocal Entity responsible for the new facility will receive an allocation adjustment for rating increases. There will be no allocation adjustments for rating decreases.

There is an equity issue involving new transmission facilities that result in an increased rating. Where a new facility involves minimal cost change (such as replacing either a WT or CT, replacing a jumper, replacing a switch, changing a CT setting, etc.), there have already been significant costs incurred on a larger conductor that allows the increased rating to occur. As long as the Reciprocal Entity making the minimal cost change is also responsible for the conductor, it is the appropriate Reciprocal Entity to receive the allocation adjustment. However, if different Reciprocal Entities own the conductor versus are responsible for making the minimal cost change, there is an equity issue if the entire allocation adjustment is given to the Reciprocal Entity responsible for making the minimal cost change. The Reciprocal Entities shall negotiate a mechanism to share in the allocation adjustment.

3. New Transmission Facilities that Involve New DNR or New Firm Transmission Service

Where a new transmission facility is added as part of an approved new usage of the transmission system (either a new DNR or a new Firm Transmission Service), the Reciprocal Entity responsible for the new facility has two choices on the treatment of this combination. First, in recognition that they have addressed transmission concerns associated with the new DNR or new Firm Transmission Service, the combination of the new transmission facility and new DNR/Firm Transmission Service will be added to the base model used in the historic usage impact calculation. The new DNR or new Firm Transmission Service will be treated as if it met the Freeze Date. To the extent the new transmission facility and its associated new DNR or new Firm Transmission Service will not occur until a future time period, they will not appear in the historic usage impact calculation until after the in-service/start date. The inclusion of the new transmission facility and associated DNR/Firm Transmission Service is dependent on having a commitment that both have been approved and will occur on the date indicated. If no such commitment exists, these additions will not be included in the historic usage impact calculation. By making this choice to include the new transmission facility and DNR/Firm Transmission Service in the historic usage impact calculation, the NNL allocation will consider the impact of both. This may result in increased NNL allocation to all Reciprocal Entities after considering historic usage impacts (down to 0%). However, the Reciprocal Entity that builds the new transmission facility will not receive any special treatment (NNL allocation adjustment) because of the new transmission facility. This inclusion of a new DNR or new Firm Transmission Service only applies where associated new transmission facilities have been added to accommodate the new transmission usage.

Second, the Reciprocal Entity that builds the new transmission facility associated with a new DNR or new Firm Transmission Service can receive an NNL allocation adjustment and must honor that allocation when they apply the new DNR or new Firm Transmission Service in their use of NNL allocations. The Reciprocal Entity determines the impact of the new transmission facility without the new DNR or new Firm Transmission Service to calculate any adjustments to the NNL allocations (the same process documented in the previous section "New Transmission Facilities that Do Not Involve New DNRs or New Firm Transmission Service"). The Reciprocal Entity will use the remaining NNL allocation that has not been committed to other uses for the new DNRs or new Firm Transmission Service.

The Reciprocal Entity responsible for the combination of new transmission facility and new DNR/Firm Transmission Service will make a single choice (either one or two) that applies to all RCFs that are significantly impacted by the combination. There is no opportunity to have a different selection on different RCFs that are all impacted by the same combination.

4. Allocation Adjustment Peer Review

When reviewing the allocation adjustments, if an impacted Reciprocal Entity finds a situation where the rule set does not produce a satisfactory outcome, the impacted Reciprocal Entity may request a review by the CMPWG. The impacted Reciprocal Entity will present the unsatisfactory results and a proposed alternative. If the CMPWG agrees to the proposed alternative it will be implemented as an exception, and the CMPC will be notified of the exception prior to implementation. If the CMPWG does not agree, the impacted Reciprocal Entity can seek further review by the CMPC. The impacted Reciprocal Entity will present its proposed alternative and the CMPWG member(s) will present their concerns to the CMPC for the CMPC to take action. All exceptions approved by the CMPWG or CMPC will be documented for future reference.

Depending on the nature of the upgrade, the impact of the new facility will be held in abeyance pending completion of the review. This means for a rating change, the prior rating will continue to be used in the model update process pending completion of the review. This means for a flow change, the new facility will be recognized in the model update process. The impacts will be calculated using the normal (socialized) allocation process and no allocation adjustments will be made pending completion of the review. These reviews should be completed in a timely manner.

Appendix H – Application of Market Flow Threshold Field Test Conditions

MISO, PJM and SPP participated in a NERC approved Market Flow threshold field test from June 1, 2007 to October 31, 2009. The purpose of the field test was to determine a Market Flow threshold percentage that allows the three Regional Transmission Organizations (RTOs) to consistently meet their relief obligations during TLR without jeopardizing reliability. Although the field test was able to achieve a success rate close to 100% based on MISO data using a 5% threshold, the following conditions were applied to the field test results:

- Market Flows were evaluated 30 minutes after implementation of the TLR curtailment.
- A 5 MW dead-band (or 10% of the relief obligation for relief obligations greater than 50 MW) was applied to the Target Market Flow such that once actual Market Flows were within the dead-band, it was considered a success meeting the relief obligation.
- There were no instances where MISO was able to meet its relief obligation if more than 30 MW must be removed within 30 minutes. The field test found the amount of Market Flow that must be removed in 30 minutes and not the size of the relief obligation is an indicator whether the market will be successful.

Since the NERC ORS applied the three conditions above to the field test results in order to demonstrate a high success rate, these same conditions will be applied when the Market-Based Operating Entities have relief obligations on external Flowgates during TLR.

The field test results are only applicable to Flowgates that are external to each of the RTOs and does not include internal Flowgates (internal to that specific RTO) or market-to-market Flowgates (internal to one of the three RTOs but subject to market-to-market provisions with another RTO). The reason for excluding internal Flowgates and market-to-market Flowgates is because the three RTOs use market redispatch to control total flow and to maintain reliability. As the Reliability Coordinator for the Flowgate, the three RTOs are responsible for the reliability of their own Flowgate and must manage total flow in order to meet their reliability responsibility. As described in the field test final report, by controlling total flow, the three markets effectively meet their relief obligation.

ATTACHMENT 2

Interregional Coordination Process

Version 1.0

MISO & SPP Market–to–Market
Interregional Coordination Process
Table of Contents

Preface

The purpose of this Interregional Coordination Process ("ICP") is to provide a description of the proposed Market-to-Market (M2M) coordination process, including the appropriate use of the M2M process, that will be implemented concurrently with the implementation of side-by-side

LMP-based energy markets in the SPP and MISO regions in accordance with this Agreement and good utility practices. Specifically, this ICP presents an overview of the M2M coordination process, an explanation of the coordination for market pricing at the regional boundaries, a description of the Real-Time and Day-Ahead coordination methodologies, an example to illustrate the Real-Time coordination, and the associated settlements processes.

1 Overview of the Market-to-Market Coordination Process

The fundamental philosophy of the SPP/MISO interregional transmission congestion coordination process is to set up procedures to allow any flowgates that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of flowgates near the market borders will provide the more efficient and lower cost transmission congestion management solution, while providing coordinated pricing at the market boundaries.

The M2M coordination process builds upon the SPP/MISO congestion management process, as described in the “Congestion Management Process” document (“CMP”) filed as part of the MISO – SPP Joint Operating Agreement. That CMP describes the interregional coordination process between a market region that uses an LMP-based congestion management regime and a market region that uses a TLR-based congestion management regime. As described in the CMP, the set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market is identified as the set of Reciprocal Coordinated Flowgates (RCFs). These RCFs are then monitored to measure the impact of market flows and parallel flows from adjacent regions. The CMP describes how the market flow impacts will be managed on an interregional basis within the existing NERC Interchange Distribution Calculator (IDC) to enhance the effectiveness of the NERC interregional congestion management process. The CMP also describes a process for calculating flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

The M2M coordination process builds on the work already completed, as described above, by adapting the coordination to the conditions that will prevail after both the SPP and MISO Day-Ahead energy markets are implemented. In addition, there is a continuing need to define the flow entitlement for network and firm transmission utilization in one region on the subset of RCFs called M2M Flowgates in an adjacent region.

- **Real-Time Energy Market Coordination** -- The M2M coordination focuses primarily on Real-Time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. This Real-Time coordination will result in a more efficient economic dispatch solution across both markets to manage the Real-Time transmission constraints that impact both markets, focusing on the actual flows in Real-Time to manage constraints. Under this approach, the flow entitlements on the M2M Flowgates do not impact the physical dispatch; the flow entitlements are used in market settlements to ensure appropriate compensation based on comparison of the actual market flows to the flow entitlements.

- **Day-Ahead Energy Market Coordination** -- The Day-Ahead market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on M2M Flowgates are reflective of the expected Real Time constraints. This coordination in the Day-Ahead market consists of both the modeling of appropriate limits on applicable Flowgates as well as a protocol that allows for the exchange of Firm Flow Entitlement between the parties.

The Parties have agreed to retain the modeling of Firm Flow Entitlements in the Day-Ahead market while deferring the implementation of the protocol in Day-Ahead (that provides for the exchange and associated settlements of Firm Flow Entitlement) until a time that is mutually agreeable to the Parties and mutually determined to provide sufficient benefits to stakeholders.

- **ARR Allocation & FTR/TCR Auction Coordination** -- The Auction Revenue Rights Allocation and Financial Transmission Rights (FTR)/Transmission Congestion Rights (TCR) auction processes in both RTOs will:

  1. as reasonably available, share information such as, but not limited to, generation and transmission outages, energy flows, shadow prices, and other information necessary to aid in the valuation of FTR/TCR's and
  2. take into account the use of Firm Flow Entitlements on M2M Flowgates.

1.1 Establishment of M2M Flowgates

Only a subset of all flowgates that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified as M2M Flowgates in a manner similar to the method used in the CMP described above. The list of M2M Flowgates will be limited to only those for which at least one generator in the adjacent market has a significant Generation-to-Load Distribution Factor (GLDF), sometimes called "shift factor," with respect to serving load in that adjacent market. NERC rules currently establish that a significant shift factor is five percent or greater. If NERC adopts a lower shift factor threshold than 5%, the new threshold will be used to determine whether the generator has a significant GLDF for the purpose of this M2M ICP. Flowgates eligible for M2M coordination are called M2M Flowgates. For the purposes of M2M coordination (in addition to the five studies for RCFs described in section 3.2.1 of the CMP) the following will be used in determining M2M Flowgates.

1.1.1 M2M Flowgates include those Reciprocal Coordinated Flowgates and any additional Flowgates which meet the criteria in this section (1.1) of the Interregional Coordination Process.

1.1.2 MISO and SPP will only be performing M2M coordination on RCFs that are under the operational control of MISO or SPP. MISO and SPP will not be performing M2M coordination on Flowgates that are owned and controlled by third party entities or on Flowgates that are only considered to be coordinated Flowgates.

1.1.3 Where the adjacent market does not have a generator with significant impact (either positive impact or negative impact) on a single-monitored element

Flowgate (i.e. shift factor is less than 5%) but its market flows are a significant portion of the total flow (greater than 25% of the Flowgate rating), these transmission constraints will be included in the list of M2M Flowgates subject to M2M coordination. If the market flow impacts of the Non-Monitoring RTO exceed 25% of the Flowgate rating during real-time operations, the Flowgate will be added as a M2M Flowgate at the request of the Monitoring RTO. The Parties agree to reevaluate, at least annually, the voltage threshold and total flow percentage cutoff for qualifying flowgates subject to M2M coordination.

1.1.4 The Parties will lower their generator binding threshold to match the lower generator binding threshold utilized by the other Party. The generator binding threshold will not be set below 1.5% except by mutual consent.(This requirement applies to M2M Flowgates. It is not an additional criteria for determination of M2M Flowgates.)

1.1.5 For the purpose of determining whether a multi-monitored element Flowgate is eligible for M2M, a progressive threshold based on the number of monitored elements will be used: a single monitored element Flowgate will use a 5% shift factor threshold; double monitored element Flowgate will use a 7.5% shift factor threshold; and a Flowgate with three monitored elements will use a 10% shift factor threshold. Flowgates with more than three monitored elements will be used only by mutual agreement.

1.1.6 For M2M Flowgates on which more than two Market Based Operating Entities (e.g., MISO, SPP and PJM) have significant impacts (either positive impact or negative impact), the Monitoring RTO of the M2M Flowgate shall identify, in advance, the partner RTO with the highest impact for the M2M coordination process. In such situations, the Monitoring RTO may initiate TLR on the constrained M2M Flowgate to request relief from the third Market Based Operating Entity having the least impact on the M2M Flowgate through the NERC TLR process.

1.1.7 The five studies for RCFs described in Section 3.2.1 of the CMP will also be performed using a -5% shift factor threshold to identify Flowgates with a significant negative impact due to market operations. Flowgates where a significant negative impact exists as measured by a -5% shift factor or more negative shift factor will be added as M2M Flowgates.

1.2 M2M Flowgate Studies

During the M2M Flowgate Studies, a M2M Flowgate may be added to the systems for operations control using the actual monitored /contingent element pair. Settlements will be implemented using a hold harmless approach as described in the After the Fact Review process set forth in Section 8.4 below.

1.2.1 MISO and SPP will implement a process whereby either RTO may request the other to enter an anticipated M2M Flowgate into the dispatch tools before the completion of the Flowgate studies when a system event requires prompt attention. Binding on the Flowgate may commence as soon as each entity's operators can make the monitored/contingent element pair available in its system. Firm Flow Entitlements shall be applied and settlements calculated after the M2M Flowgate is approved by both entities.

1.2.2 Use of a M2M Flowgate Before Completion of the Studies:

The use of an anticipated Flowgate while the Flowgate is undergoing the M2M Flowgate Studies is described in CMP Section 3.2.5 Dynamic Creation of Coordinated Flowgates. These will typically be limited to forced outages since there should be time to evaluate the potential new M2M Flowgate before the planned outage is taken. However, the need for a new Flowgate is not always identified in advance. The Parties will ensure the time period to run the coordinated Flowgate test and have these Flowgates ready for the market-to-market process is as short as possible.

1.3 Removal of M2M Flowgates

Removal of M2M Flowgates from the systems may be necessary under certain conditions including the following:

1.3.1 Where Information Technology systems cannot support the operation of a defined M2M Flowgate effectively, the first attempt will be to find a mutually acceptable temporary work-around that will allow the continued use of the M2M process. Where a temporary work-around is not available, the M2M process will be suspended on that M2M Flowgate until Information Technology system enhancements allow re-establishing the M2M Flowgate. The Party responsible for IT system enhancements will take all practicable steps to minimize the period of the suspension.

1.3.2 A M2M Flowgate is no longer valid when either a temporary M2M Flowgate or a transmission system change is implemented such that the Flowgate no longer passes the M2M Flowgate Studies.

a. Once a M2M Flowgate becomes a completely invalid constraint, it will no longer be bound in the monitoring RTO's Unit Dispatch System (UDS)/Real-Time Balancing Market (RTBM).

b. A Flowgate that is removed from the M2M Flowgate list but remains a valid constraint may continue to be bound in the Monitoring RTO's UDS/RTBM, but the M2M process will no longer be initiated on it.

1.3.3 The RTOs will collaborate to address specific scenarios where generation is not responding to dispatch signals (e.g., self scheduled) and the generation does, or could, significantly impact an M2M Flowgate and/or resulting M2M settlement.

1.3.4 The Parties can mutually agree to add or remove a Flowgate from the market-to-market process whether or not it passes the coordination tests, or whether or not it is a Reciprocal Coordinated Flowgate. A M2M Flowgate may be removed when the Parties agree that the M2M process would not be an effective mechanism to manage congestion on that Flowgate.

2 Interface Bus Price Coordination

Proxy Bus prices are calculated by each RTO to reflect the economic value of imports or exports from the neighboring RTO. For example, the Proxy Bus price for RTO A as calculated by RTO B is driven by the economic dispatch of RTO B, therefore this proxy price will reflect the system marginal price in RTO B, plus any congestion cost adjustment and marginal loss cost adjustment based on the Proxy Bus location. The coordinated operation of M2M Flowgates will tend to force the pricing at the RTO borders to be consistent with the energy prices at generators and load busses near the RTO border points.

In order to be good functional indicators for the M2M coordination, the Proxy Bus models for SPP and MISO must be coordinated to the same level of granularity. Therefore, the Proxy Bus modeling approaches must be similar such that the prices are consistent. This does not necessarily mean the Proxy Bus prices will be the same, particularly in the initial implementation of M2M coordination. What is important at the outset is that the Proxy Buses reflect consistent pricing between the RTOs given the constraints for which each RTO is operating. Consistency means that the Proxy Bus price one RTO calculates for the other RTO reflects the nature of the congestion on both RTOs' systems, such that imports and exports to and from one RTO to the other are provided the correct incentives given their effect on the current binding constraints. A description of the current Proxy Bus modeling process used by SPP and MISO shall be posted on each RTO's OASIS.

As the M2M coordination process continues to evolve, it may be possible to get to the point that each RTO's Proxy Bus prices for the other is consistently close. This will require coordination beyond merely operating for constraints on each other's systems, to include tightly coordinating the economic dispatches themselves, in an iterative process as described in Section 7.

3 Real-Time Energy Market Coordination

When an M2M Flowgate that is under the operational control of either MISO or SPP become binding in the Monitoring RTOs Real-Time security constrained economic dispatch, the Monitoring RTO will notify the Non-Monitoring RTO of the transmission constraint violation and will identify the appropriate M2M Flowgate that requires mitigation. The Monitoring and Non-Monitoring RTOs will provide the economic value of the constraint ("Constraint Shadow Price") as provided by their respective market systems. Using this information, the security-constrained economic dispatch of the Non-Monitoring RTO will include the transmission constraint; the Monitoring RTO will evaluate the shadow prices within each RTO and request that the Non-Monitoring RTO reduce its market flow if it can do so more efficiently than the Monitoring RTO (i.e., the Non-Monitoring RTO has a lower shadow price than the Monitoring RTO).

An iterative coordination process will be supported by automated data exchanges in order to ensure the process is manageable in a real-time environment. The process of evaluating the shadow prices between the RTOs will continue until the shadow prices are sufficiently close that an efficient redispatch solution is achieved. The continual iterative process over the next several dispatch cycles will allow the transmission congestion to be managed in a coordinated, cost-effective manner by the RTOs. A more detailed description of this iterative procedure will be discussed in Sections 3.1 and 3.2.

This coordinated dispatch protocol will be performed any time that an M2M Flowgate under the operational control of either MISO or SPP becomes binding. This approach will produce the level of coordination that will be required to ensure efficient congestion management across the market seams. This approach also will provide a much higher level of interregional congestion management coordination than that which currently exists between any existing adjacent markets.

3.1 Real-Time Energy Market Coordination Procedures

Unless mutual agreement is reached to manage the real time coordination as listed in section 3.2, the following procedure will apply for managing M2M Flowgates in the real- time energy market:

1. The RTOs will exchange topology information to ensure that their respective market software is consistent.

2. When any of the M2M Flowgates under a Monitoring RTO's control is identified as a transmission constraint violation, the Monitoring RTO will enter the M2M Flowgate into its security-constrained dispatch software, setting the flow limit equal to the Effective Limit required for reliability.

3. The Monitoring RTO will then notify the Non-Monitoring RTO of the transmission constraint violation and will identify the appropriate M2M Flowgate that requires mitigation.

4. When the M2M Flowgate first becomes a binding transmission constraint in the Monitoring RTOs real-time security-constrained economic dispatch, the Monitoring RTO will transmit the following information to the Non-Monitoring RTO:

   - Current Constraint Shadow Price ($/MW) - output of the RTOs real-time market software.

   - Current Market Flow contribution by the Monitoring RTO on M2M Flowgate (MW) - output of the real-time market software.

   - Amount of MWs requested to be reduced from the current market flow of the Non-Monitoring RTO. This number will change throughout the iterative process to efficiently resolve constraints.

5. The Non-Monitoring RTO will enter the M2M Flowgate into its security-constrained economic dispatch software, setting the flow limit on the M2M Flowgate equal to its current market flow minus the relief requested by the Monitoring RTO.

   (a) This means the Non-Monitoring RTO will attempt to manage the flow on the M2M Flowgate at its current Market Flow amount or less, such that it will not contribute any additional flow on the limited M2M Flowgate during this time period.

6. If the Non-Monitoring RTO has sufficient generation to be redispatched, it will redispatch its generation to control the M2M Flowgate until one of the following conditions is reached:

    (a) The Non-Monitoring RTO has provided the relief requested by the Monitoring RTO.

    (b) The Non-Monitoring RTO has provided relief at a cost as high as the current Constraint Shadow Price provided by the market system of the Monitoring RTO.

7. The Non-Monitoring RTO will then transmit the following information to the Monitoring RTO:

    - Current Constraint Shadow Price (S/MW) - Output of the RTOs real-time market software. (If the M2M Flowgate does not result in a binding constraint in the Non-Monitoring RTO's security-constrained economic dispatch, then the shadow price is zero and the flow relief is zero for the Non- Monitoring RTO.)

    - Current market flow contribution by the Non-Monitoring RTO on M2M Flowgate (MW) - Output of the RTO's real-time market software.

8. Over the next several dispatch cycles the Monitoring RTO may request the Non-Monitoring RTO to adjust its flow limit up or down. The Monitoring RTO will continue to control the M2M Flowgate respecting the Effective Limit of the facility required for reliability.

9. As the relief provided by the Non-Monitoring RTO is realized in the M2M Flowgate, the Monitoring RTO can control the M2M Flowgate at a lower shadow price since less relief is needed from the Monitoring RTO. The updated shadow price will be sent to the Non-Monitoring RTO. The Non-Monitoring RTO will then control the M2M Flowgate using the current Constraint Shadow Price from the Monitoring RTO as the Constraint Shadow Price limit.

10. Throughout the period that the transmission constraint violation exists, the RTOs will continue to share the flow and constraint shadow price information that is described above. The shadow prices of the two RTOs will eventually converge towards the most cost-effective redispatch solution, provided both RTOs have sufficient redispatch capability. The information transferred via these data exchanges will be retained to provide the pertinent data for Market Settlements.

11. Every 15 to 30 minutes or as necessary, the Monitoring RTO will review the Constraint Shadow Price comparison, make required adjustments, and communicate any such adjustments to the Non-Monitoring RTO. This process

will continue until the Monitoring RTO determines that the cost of further adjustments to the dispatch of the Non-Monitoring RTO would exceed the cost of relieving the transmission constraint by adjusting the Monitoring RTO’s own dispatch.

12. The start and stop times for such Constrained Operation events involving M2M Flowgates will be logged for Market Settlements purposes.

3.2 Real-Time Energy Market Coordination Procedures for Flow Volatility

The Non-Monitoring RTO managing to total flows will only be applied to a M2M Flowgate where the Non-Monitoring RTO has demonstrated more effective control of the constraint. To better manage congestion volatility in real-time, the Non-Monitoring RTO may control to total flows for the M2M Flowgate rather than Market Flows if the M2M Flowgate qualifies as a candidate under each of the following conditions:

a. Demonstration based on historical data that the Non-Monitoring RTO has a significant control of flow on the M2M Flowgate. Significant control criteria includes:

    i. The Non-Monitoring RTO has predominant flow on the M2M Flowgate and has the better ability to control the M2M Flowgate, or;

    ii. The Non-Monitoring RTO has effective generation to control the M2M Flowgate in real-time.

b. The Non-Monitoring RTO should have a network model with sufficient details around the M2M Flowgate to calculate credible post-contingent flows for OTDF M2M Flowgates and real-time flows for PTDF M2M Flowgates.

c. Confirmation that each RTO's dispatch model observes the same or similar total post-contingent flows or real-time flows. A comparison may be completed prior to both RTOs agreeing to switch control.

d. The Non-Monitoring RTO managing to total flows can only be used on basis of mutual agreement between the Monitoring RTO and the Non-Monitoring RTO. Either RTO may withdraw mutual agreement with prior notification and coordination. The RTOs will then revert to the M2M Procedure in Section 3.1.

If the RTOs have mutually agreed that the M2M Flowgate will be subject to the Non-Monitoring RTO binding to total flows and the aforementioned criteria are met, the following procedure will be applied:

1. The Monitoring RTO may initiate M2M utilizing steps 1 through 3 described in 3.1.

2. The Non-Monitoring RTO will start to manage the total flow of the M2M Flowgate in its real-time security-constrained economic dispatch, and transmit the following information to the Monitoring RTO:

    - Current Constraint Shadow Price ($/MW) - output of the RTOs real-time market software.

- Current Market Flow contribution by the Non-Monitoring RTO on M2M Flowgate (MW) - output of the real-time market software.
- Amount of MWs requested to be reduced from the current Market Flow of the Monitoring RTO. This number will change throughout the iterative process to efficiently resolve constraints.

3. The Monitoring RTO will set the flow limit on the M2M Flowgate equal to its current Market Flow minus the relief requested by the Non-Monitoring RTO.

   (a) This means the Monitoring RTO will attempt to manage the flow on the M2M Flowgate at its current Market Flow amount or less, such that it will not contribute any additional flow on the limited M2M Flowgate during this time period.

4. If the Monitoring RTO has sufficient generation to be redispatched, it will redispatch its generation to control the M2M Flowgate until one of the following conditions is reached:

   (a) The Monitoring RTO has provided the relief requested by the Non-Monitoring RTO.

   (b) The Monitoring RTO has provided relief at a cost as high as the Shadow Price provided by the market system of the Non-Monitoring RTO.

5. The Monitoring RTO will then transmit the following information to the Non-Monitoring RTO:

   - Current Constraint Shadow Price ($/MW) - Output of the RTOs real-time market software. (If the M2M Flowgate does not result in a binding constraint in the Monitoring RTO's security-constrained economic dispatch, then the shadow price is zero and the flow relief is zero for the Monitoring RTO.)
   - Current Market Flow contribution by the Monitoring RTO on M2M Flowgate (MW) - Output of the RTO's real-time market software.

6. Over the next several dispatch cycles the Non-Monitoring RTO may request the Monitoring RTO to adjust its flow limit up or down. The Non-Monitoring RTO will continue to control the M2M Flowgate respecting the appropriate rating of the facility, per the communication from the Monitoring RTO.

7. As the relief provided by the Monitoring RTO is realized in the M2M Flowgate, the Non-Monitoring RTO can control the M2M Flowgate at a lower shadow price since less relief is needed from the Non-Monitoring RTO. The updated shadow price will be sent to the Monitoring RTO. The Monitoring RTO will then control the M2M Flowgate using the

current Constraint Shadow Price provided by the Non-Monitoring RTO as the Constraint Shadow Price limit.

8. Throughout the period that the transmission constraint violation exists, the RTOs will continue to share the flow and constraint shadow price information that is described above. The shadow prices of the two RTOs will eventually converge towards the most cost-effective redispatch solution, provided both RTOs have sufficient redispatch capability. The information transferred via these data exchanges will be retained to provide the pertinent data for Market Settlements.

9. Every 15 to 30 minutes or as necessary, the Non-Monitoring RTO will review the constraint shadow price comparison, make required adjustments, and communicate any such adjustments to the Monitoring RTO. This process will continue until the Non-Monitoring RTO determines that the cost of further adjustments to the dispatch of the Monitoring RTO would exceed the cost of relieving the transmission constraint by adjusting the Non-Monitoring RTO’s own dispatch.

10. If the Non-Monitoring RTO is not able to control the total flows of the M2M Flowgate, the Monitoring RTO may request to stop the Non-Monitoring RTO controlling to total flows and switch back to normal procedure as described in section 3.1, or may decide to take other steps to control total flows on the M2M Flowgate.

11. The start and stop times for such Constrained Operation events involving M2M Flowgates will be logged for Market Settlements purposes.

3.3 Real-Time Energy Market Settlements

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

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

Payment = (Real-Time Market Flow MW[1] – (Firm Flow Entitlement MW[2] + Approved MW[3])) * Transmission Constraint Shadow Price in Monitoring RTOs Dispatch Solution

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

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

For the purpose of settlements calculations, shadow prices will be calculated by the pricing software in the same manner as the LMP, and will be integrated over each hour during which a transmission constraint is being actively coordinated under the ICP by summing the five-minute shadow prices during the active periods within the hour and dividing by 12 (the number of five minute intervals in the hour). Make-whole payments for Market Participants are not considered for M2M settlement purposes.

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[1] This value represents the Non-Monitoring RTO's Real Time Market Flow.

[2] This value represents the Non-Monitoring RTO's Firm Flow Entitlement.

[3] This value represents the Approved MW that resulted from the Day Ahead Coordination if and when the Parties mutually agree to implement such provisions.

3.4 Real-Time Energy Market Coordination Procedures for Overlapping Congestion

Overlapping congestion charges on a pseudo-tied load or resource originate when an RCF binds simultaneously in both RTOs, and MISO and SPP each react to relieve the constraint, resulting in the provision, in the aggregate, of more relief than necessary to relieve the constraint — i.e., relief beyond the optimal level of redispatch. To proactively eliminate or greatly reduce the potential for overlapping congestion charges to be assessed to a pseudo-tied load or resource in real-time, the RTOs will utilize the predictive flow factor process for the M2M Flowgate if the M2M Flowgate qualifies under the following condition:

a. M2M Flowgate is impacted five percent (5%) or greater by any load or resource asset pseudo-tied between the RTOs.

4 Day-Ahead Energy Market Coordination

The Day-Ahead energy market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on applicable M2M Flowgates are reflective of the Firm Flow Entitlements for each RTO with an objective of coordinating the utilization of Reciprocal Coordinated Flowgates. This coordination in the Day-Ahead market consists of both the modeling of appropriate limits on applicable Flowgates as well as a protocol that allows for the exchange of Firm Flow Entitlement between the parties as described in the example below.

The Day-Ahead energy market redispatch protocol may be implemented in the Day-Ahead energy market upon the request of either RTO if the adjacent RTO verifies that such Day-Ahead redispatch is feasible.

The Parties have agreed to retain the modeling of Firm Flow Entitlements in the Day-Ahead market while deferring the implementation of the protocol in Day-Ahead (that provides for the exchange and associated settlements of Firm Flow Entitlement) until a time that is mutually agreeable to the Parties and mutually determined to provide sufficient benefits to stakeholders. Deferral of this coordination will not affect M2M coordination or settlements in real-time.

An example of the Day-Ahead energy market protocol is as follows:

1. The Requesting RTO specifies the amount of scheduled flow reduction that it is requesting on a specific M2M Flowgate and communicates the request to the Responding RTO

2. The Responding RTO will then lower the MW limit that it utilizes in its Day-Ahead market on the specified M2M Flowgate by the specified amount. This means that instead of modeling the M2M Flowgate constraint at flow entitlement amount, the Responding RTO will model the constraint as the flow entitlement less the requested MW reduction. Therefore, the Responding RTO will schedule less flow on the specified M2M Flowgate in order to provide Day-Ahead congestion relief for the Requesting RTO. The Requesting RTO may then use the additional MW capability in its own Day-Ahead market.

4.1 Day-Ahead Energy Market Firm Flow Entitlement Modeling

With the purpose of this Day-Ahead coordination to better align with the expected operation in real-time, each Party will model in the Day-Ahead market M2M Flowgates that are expected to be congested based on forecasted system conditions, or have recently bound in real-time by applying the following guidelines:

- Each RTO will model the applicable M2M Flowgates in its Day-Ahead market ensuring that the limits consider an estimation of the Firm Flow Entitlement for the next operating day. Firm Flow Entitlements used for real-time settlement purposes are calculated on the effective operating day using actual schedules and hence are not available in time for the clearing of the Day-Ahead market.

- Each RTO should represent External M2M Flowgate limits that include consideration of its Firm Flow Entitlements on the Monitoring RTO's facilities. Each RTO should represent internal M2M Flowgate limits that include consideration of Firm Flow Entitlements of the Non-Monitoring RTO. The Monitoring RTO should also include additional considerations such as de-rates on the facility resulting from expected system condition as well as parallel flow from non-reciprocal entities. The Monitoring RTO should include an appropriate loop flow model in its Day-Ahead process. However, this loop flow model will not account for loop flows contributed by deliveries associated with the Non-Monitoring RTO market since these flows are accounted for by the Firm Flow Entitlement.

4.2 Day-Ahead Energy Market Firm Flow Entitlement Exchange and Settlement

An M2M Flowgate limit change is a request to better reflect the anticipated M2M Flowgate limits, as described above, that will be modeled in the Day-Ahead markets. The following procedure will apply for designating such changes to the M2M Flowgate limit:

1. Prior to 0800 EST on the day before the Operating Day, if the Requesting RTO identifies a need to utilize more of an M2M Flowgate than it is entitled, it may request the Responding RTO to lower its Day-Ahead Market limit below its Firm Flow Entitlement by a specified amount for a specified range of hours.

2. If the Responding RTO agrees to provide the limit reduction, it will communicate the approved amount to the Requesting RTO by 1000 EST.

3. The Requesting RTO may increase its limit on the M2M Flowgate by the specified amount for the specified range of hours.

The Parties have agreed to retain the modeling of Firm Flow Entitlements in the Day-Ahead Market while deferring the implementation of the protocol in Day-Ahead (that provides for the exchange and associated settlements of Firm Flow Entitlement) until a time that is mutually agreeable to the Parties and mutually determined to provide sufficient benefits to stakeholders. Deferral of this coordination will not affect Market-to-Market coordination or settlements in real time.

4.3 Day-Ahead Energy Market Settlements

The market settlements for Day-Ahead congestion relief will be performed in a similar manner to the Real-Time energy market settlements of the coordinated congestion management protocol. The Day-Ahead payment for the RTO that is requesting congestion relief will be calculated as follows:

Requesting RTO Payment to Responding RTO = Approved Day- Ahead Adjustment for M2M Flowgate * Responding RTOs M2M Flowgate constraint shadow price.

This payment will be calculated based on the hourly Day-Ahead Market results. If such congestion relief is requested and performed on a Day-Ahead basis, then the Real- Time flow entitlement for the affected hours in the corresponding Real-Time market will be adjusted accordingly.

The Parties have agreed to retain the modeling of Firm Flow Entitlements in the Day-Ahead Market while deferring the implementation of the protocol in Day-Ahead (that provides for the exchange and associated settlements of Firm Flow Entitlement) until a time that is mutually agreeable to the Parties and mutually determined to provide sufficient benefits to stakeholders. Deferral of this coordination will not affect Market-to-Market coordination or settlements in real time.

5 Auction Revenue Rights (ARR) Allocation/Financial Transmission Rights (FTR)/Transmission Congestion Rights (TCR) Auction Coordination

The allocation of ARR and FTR/TCR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. The ARR allocation and FTR/TCR Auction model will contain the same level of detail for adjacent regions as the Day-Ahead market model and the Real-Time market model. Each RTO will allocate ARRs via Annual ARR Allocation award, and award FTRs/TCRs via Annual and Monthly FTR/TCR Auction to Network and Firm Transmission customers subject to their participation and simultaneous feasibility test that determines the amount of transmission capability that exists to support the ARRs and FTRs/TCRs.

The simultaneous feasibility analysis for each RTO will take into account that RTO's estimate of Firm Flow Entitlement on the transmission flowgates in the adjacent region as the market flow limit that must be respected in the ARR Allocation and FTR/TCR Auction processes. The transmission flowgates in each RTO will be modeled in the simultaneous feasibility test at a capability value equal to the flowgate rating minus the applicable parallel flows including estimated Firm Flow Entitlement that exists for flows from the adjacent market. In this way, the ARR Allocation and the FTR/TCR Auction across both RTOs will recognize the reciprocal transmission utilization that exists for Network and Firm transmission customers in both markets.

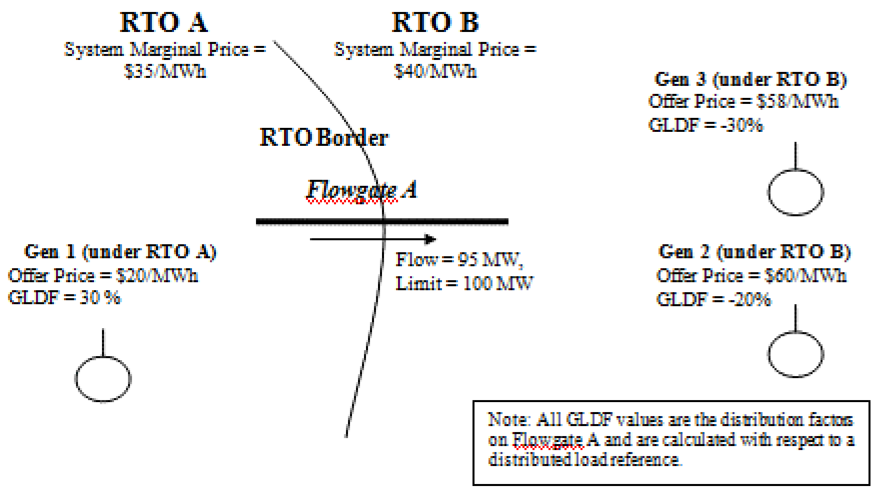
6 Coordination Example

The following example illustrates the Real-Time coordination of an M2M Flowgate, specifically describing the following five stages:

- Stage 1: Initial Conditions & Energy Prices at Border
- Stage 2: Transmission Constraint Initialization & Energy Prices at Border
- Stage 3: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO) & Energy Prices at Border
- Stage 4: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Non-Monitoring RTO) & Energy Prices at Border
- Stage 5: Ongoing Coordinated Dispatch Cycles

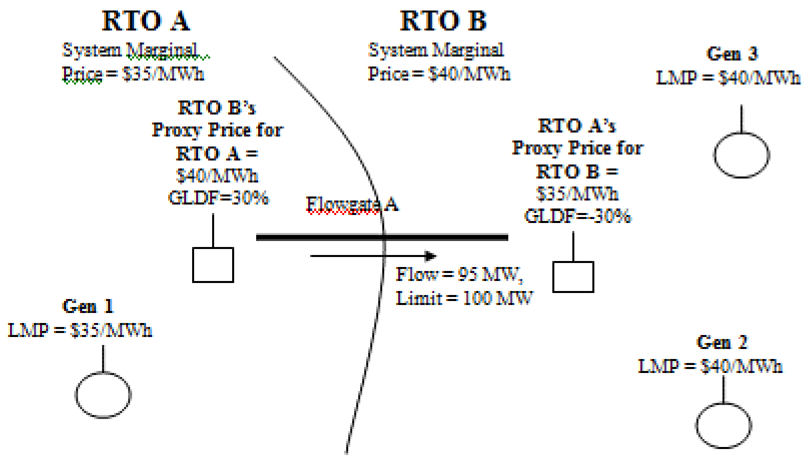
Stage 1 – Initial Conditions

- Marginal Losses are not utilized in this example for ease of understanding
- RTO A is the Non-Monitoring RTO, its system marginal price is $35/MWh
- RTO B is the Monitoring RTO, its system marginal price is $40/MWh
- Generator 1 is on-line and dispatched to full output, its dispatchable range is 100 MW
- Generators 2 and 3 are both off-line; they are both 20 MW quick start CTs
- M2M Flowgate A has a limit of 100 MW with the actual flow at 95 MW



Stage 1 - Energy Prices at the RTO Border (Proxy Bus Prices)

The Proxy Bus prices will be calculated for each stage of the congestion management example. These examples illustrate that the Proxy Bus prices will move in the same direction as the constrained bus prices when the M2M Flowgate is binding in both RTO security-constrained economic dispatches. The LMPs throughout both RTOs are equal to their System Marginal Price so long as the RTOs are unconstrained (no binding constraint resulting in redispatch of generation). This example also ignores marginal losses to simplify the illustration.



Stage 2 - Transmission Constraint Initialization

The RTO B (Monitoring RTO) dispatch software is projecting that the flow on Flowgate A is increasing and that 9 MW of flow relief will be required. (Note: The 9 MW is derived from RTO B's look-ahead dispatch software along with a parallel path evaluation). The security-constrained dispatch solution for RTO B results in both Generator 2 and Generator 3 being dispatched; the system marginal price for RTO B remains at S40/MWh. Generator 3 is the most cost effective unit to control the constraint.

The Flowgate A constraint shadow price for RTO B will be equal to:

(Gen 2 Offer Price – System Marginal Price for RTO B)/(Generator 2 GLDF on Constraint)

($60/MWh-$40/MWh) /-0.20 = -$100/MW of Flow Relief.[1]

[1] The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF.

The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

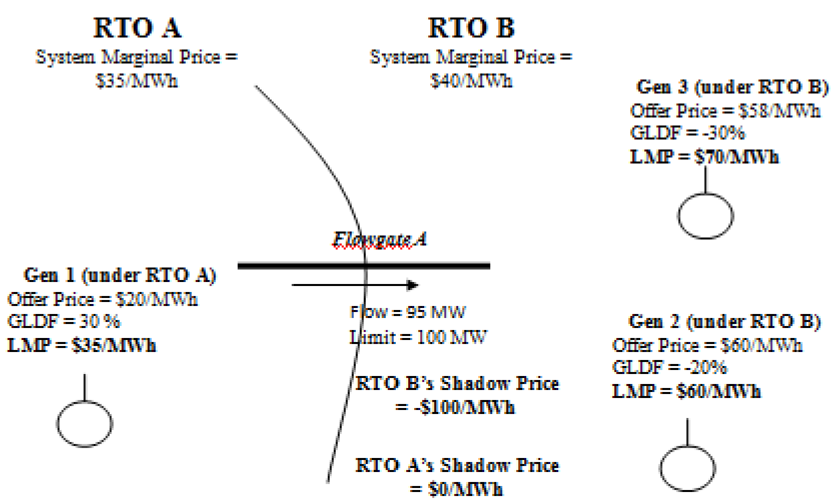
$40/MWh + (-.2)(-$100/MWh flow relief) = $60/MWh

The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

$40/MWh + (-.3)(-$100/MWh flow relief) = $70/MWh

The conditions for Stage 2, the initial transmission constrained scenario, are as follows:



Stage 2 - Energy Prices at the RTO Border (Proxy Bus Prices)

The Proxy Bus price for RTO A as calculated by RTO B will include the impact of the constraint on Flowgate A.

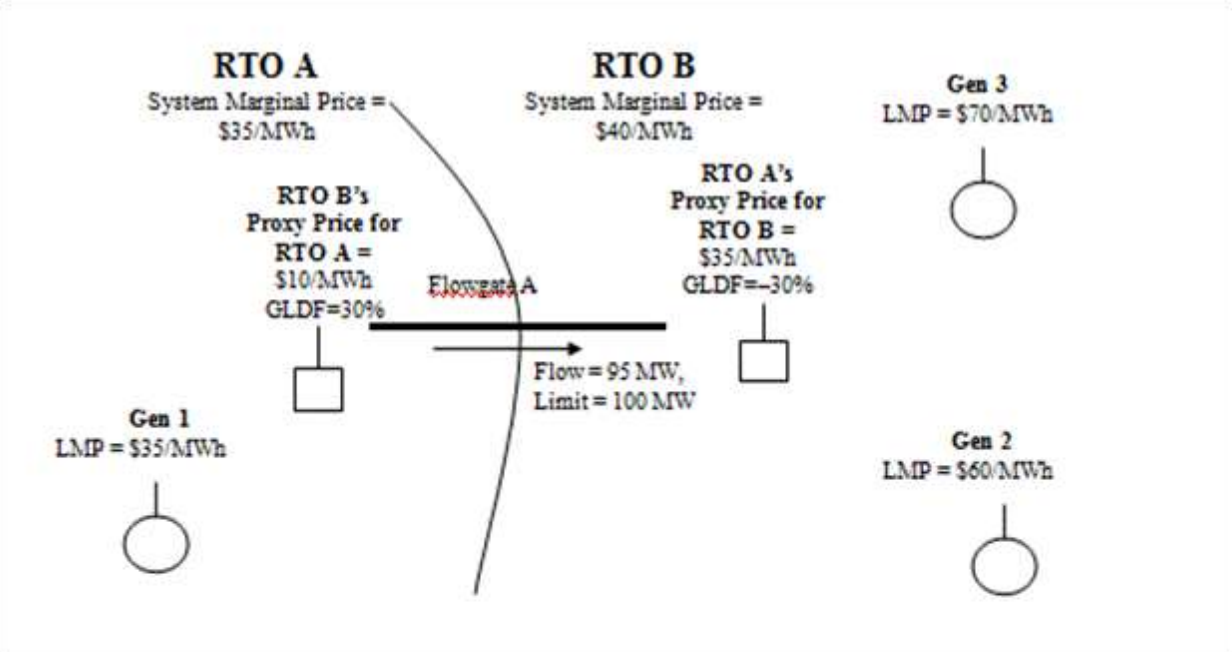
- Since the constraint is not binding in RTO A in Stage 2, the proxy price for RTO B as calculated by RTO A will remain at the system marginal price of RTO A.

- Since the Proxy Bus prices for each RTO reflect the value of imports or exports from the neighboring RTO, these proxy prices will be set by the system marginal price in the RTO that is calculating the proxy price.

RTO B's Proxy price for RTO A is as follows:

System Marginal Price for RTO B + (Proxy bus GLDF)(RTO B Shadow Price)

$40/MWh + (.3)(-$100/MWh flow relief) = $10/MWh



Stage 3 – First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO)

- RTO B notifies RTO A of the transmission constraint Condition on Flowgate A. Initially RTO B requests RTO A to maintain its current market flow on Flowgate A. RTO B sends its latest shadow price of –$100/MWh to RTO A.

- RTO A enters the constraint into its security-constrained dispatch software with the current flow equal to the limit using –$100/MWh as its shadow price limit. (The current flow equals 95 MW in this case.) Since RTO A's load is growing, the constraint binds with a shadow price less than the –$100/MWh limit. (Assume Firm Flow is 40 MW.).

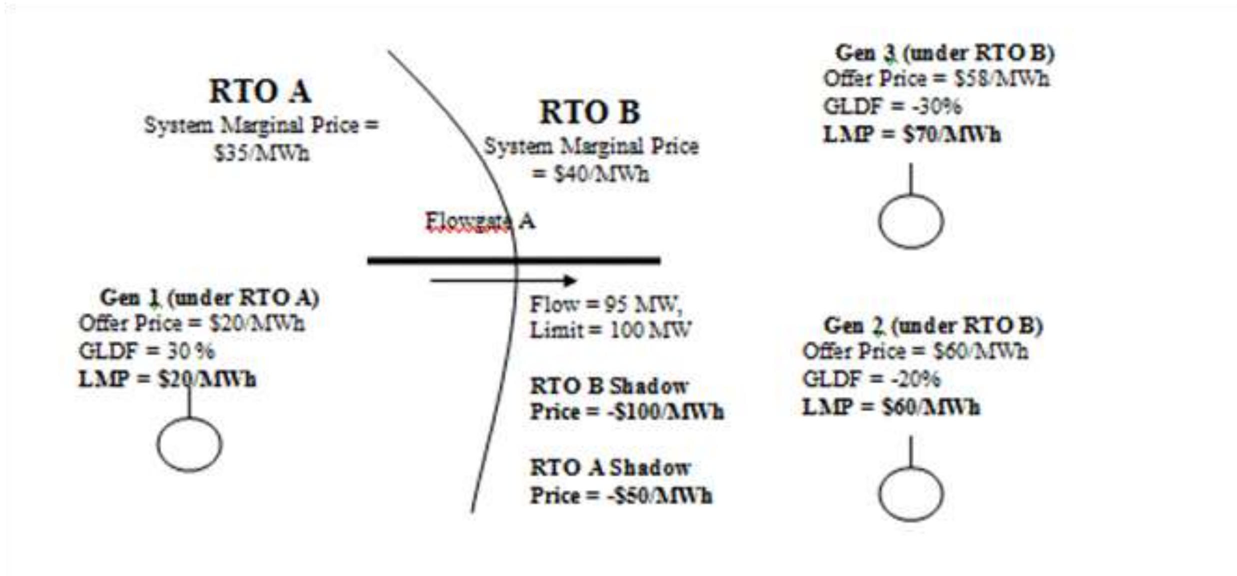
Flowgate A constraint shadow price for RTO A will be equal to:

(Gen 1 Offer Price – System Marginal Price for RTO A)/(Gen 1 GLDF on Constraint)
($20/MWh-$35/MWh) /0.30 = -$50/MW of Flow Relief.[2]

The LMP for Gen 1 will be:

System Marginal Price for RTO A + (Gen 1 GLDF)(RTO A Shadow Price) $35/MWh + (.3)(-$50/MWh flow relief) = $20/MWh

[2] The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF. The resulting shadow price of -$50/MWh is less than the limit of -$100/MWh from the Monitoring RTO A.



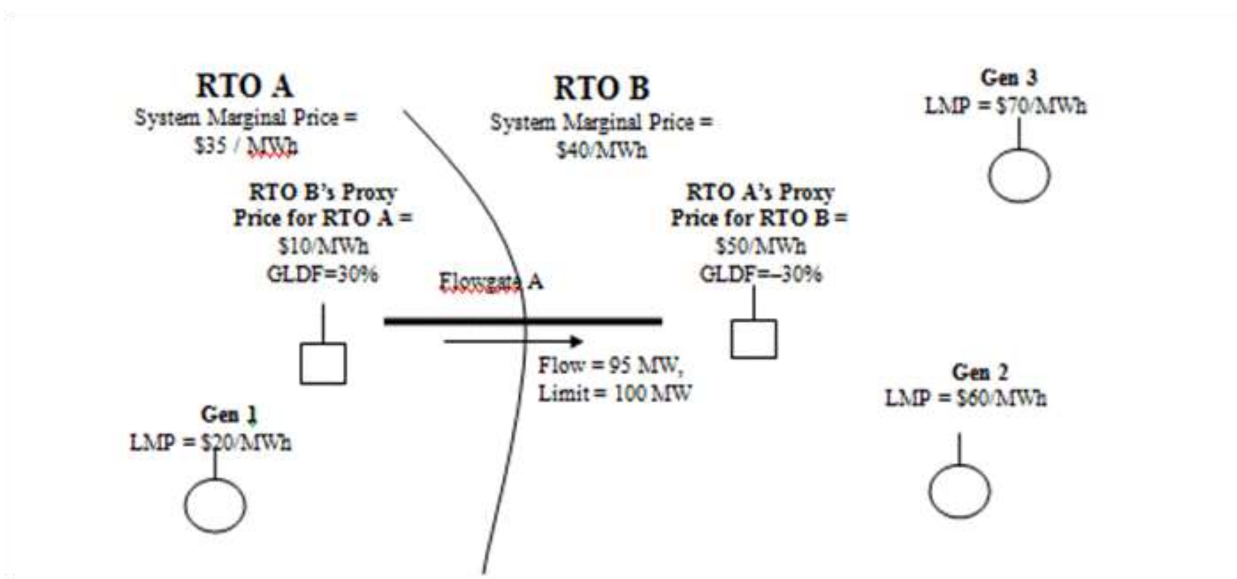
Stage 3 - Energy Prices at the RTO Border (Proxy Bus Prices)

The Proxy Bus price for RTO A as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint is now binding in RTO A in stage 3, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

RTO A's Proxy price for RTO B is as follows:

System Marginal Price for RTO A + (Proxy bus GLDF)(Shadow Price)

\$35/MWh + (-.3)(-\$50/MWh flow relief) = \$50/MWh



Stage 4 – First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Non-Monitoring RTO)

RTO B analyzes the constraint shadow price information and determines that RTO A has a more economical alternative to provide the Flow Relief than is currently being obtained by operating Generator 2 out of merit. The analysis results in RTO B requesting RTO A to provide 4 MW more of Flow Relief to enable Generator 2 to come offline.

RTO A is able to reduce its market flow on Flowgate A to the desired 31 MW limit in its dispatch software. RTO A can achieve the requested relief by lowering Gen 1 while observing the shadow price limit from RTO B.

After the flow on Flowgate A is reduced by the redispatch action from RTO A, RTO B requests Generator 2 to come off-line, because it will no longer be required to control the Flowgate A limit.

The Flowgate A constraint shadow price for RTO B will be equal to:

(Gen 3 Offer Price – System Marginal Price for RTO B)/(Generator 3 GLDF on Constraint)
($58/MWh-$40/MWh) /-0.30 = -$60/MW of Flow Relief.[3]

The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

$40/MWh + (-.2)(-$60/MWh flow relief) = $52/MWh

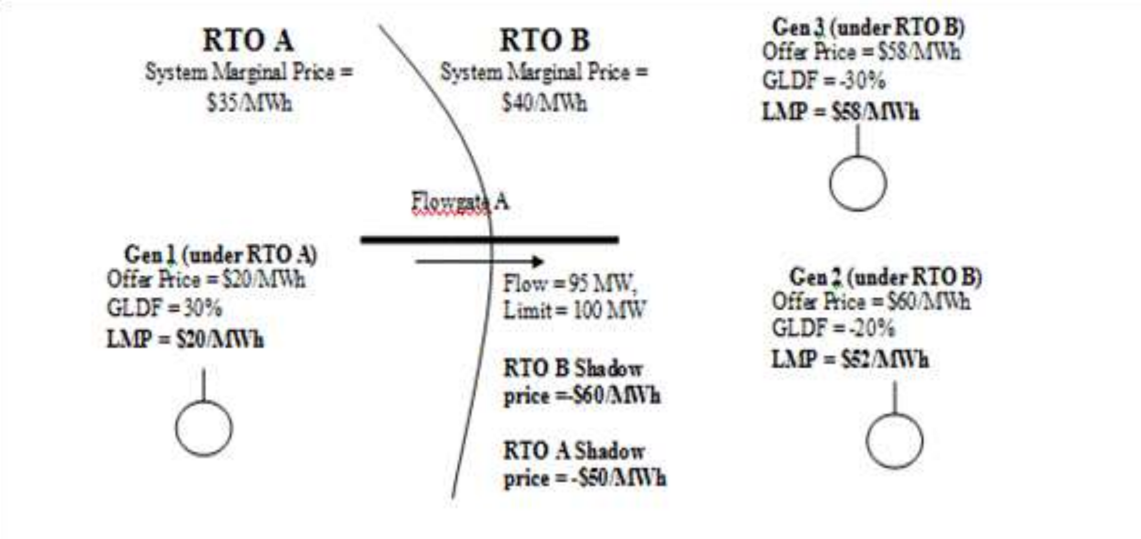
The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

$40/MWh + (-.3)(-$60/MWh flow relief) = $58/MWh

[3] The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 3 drives the constraint shadow price because it is the only unit online for the constraint.

The conditions for Stage 4 are as follows:

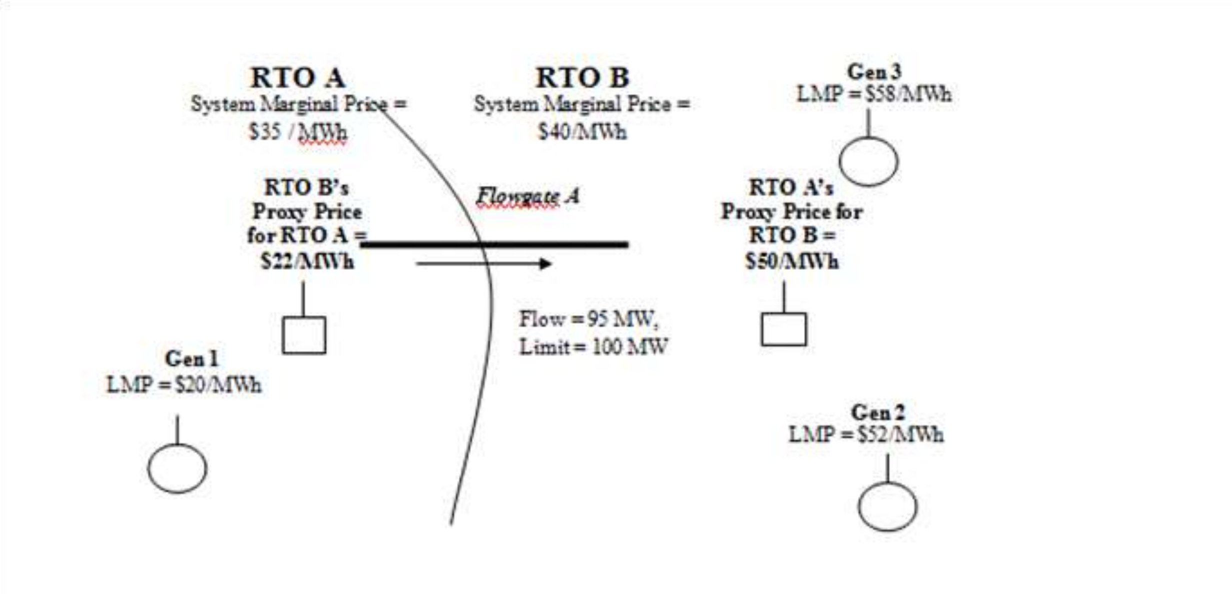


Stage 4 - Energy Prices at the RTO Border (Proxy Bus Prices)

The Proxy Bus price for RTO A, as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint remains binding in RTO A in Stage 4, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A. RTO B's Proxy price for RTO A is as follows:

System Marginal Price for RTO B + (Proxy bus GLDF)(RTO B Shadow Price)

$40/MWh + (.3)(-$60/MWh flow relief) = $22/MWh



Stage 5 – Ongoing Coordinated Dispatch Cycles

As the constrained operations progress, the RTOs will periodically verify that the constrained operations are coordinated by ensuring that the constraint shadow prices are converging for the given constrained scenario.

In this case, the RTO A shadow price is $50/MWh and the RTO B shadow price is $60/MWh, which indicates that the system is optimally coordinated for the given constrained condition.

The RTO B's Proxy Bus price for RTO A is $22/MWh which is very close to the LMP at Gen 1 bus ($20/MWh) in RTO A. The RTO B's Proxy Bus for RTO A and the Gen 1 bus both have +30% GLDF on Flowgate A. One of the objectives of the M2M coordination is to achieve price convergence for buses with similar GLDFs across the RTO border. Similarly, the RTO A's Proxy Bus price for RTO B is $50/MWh which is reasonably close to the LMP at Gen 3 bus ($58/MWh) in RTO B. The RTO A's Proxy Bus for RTO B and the Gen 3 bus both have -30% GLDF on Flowgate A.

Settlement calculations

Stages 4 and 5 are the steady state situation integrated over an hour.

Firm Flow Entitlement for RTO A on Flowgate A per the example = 40MW

Real-Time Market Flow MW by RTO A on Flowgate A = 31MW (requested by RTO B)

RTO A Shadow Price on Flowgate A = -$50/MWh

Payment (RTO B to RTO A) = ((Firm Flow Entitlement MW + Approved MW) – Real-Time Market Flow MW) * Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution

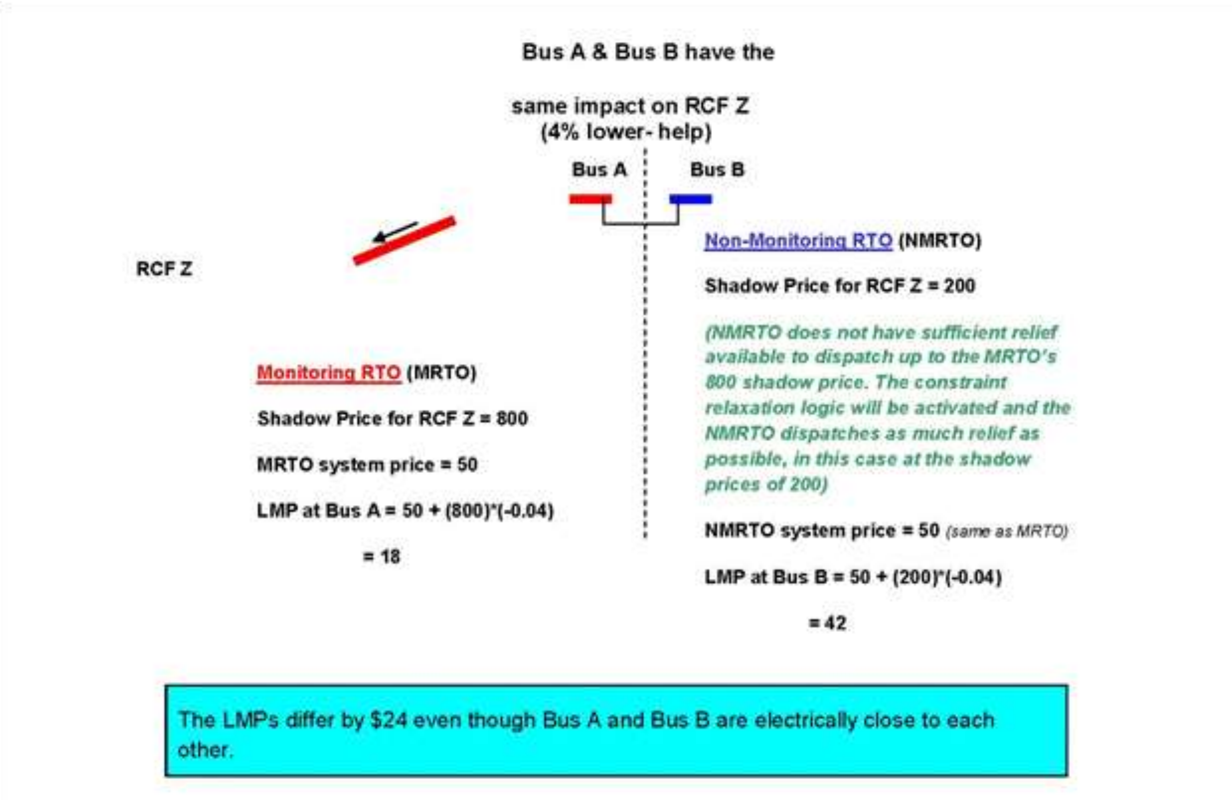
Payment (RTO B to RTO A) = ((40/MWh + 0) -31/MWh)*-$50/MWh

Payment (RTO B to RTO A) = $450

7 When One of the RTOs Does Not Have Sufficient Redispatch

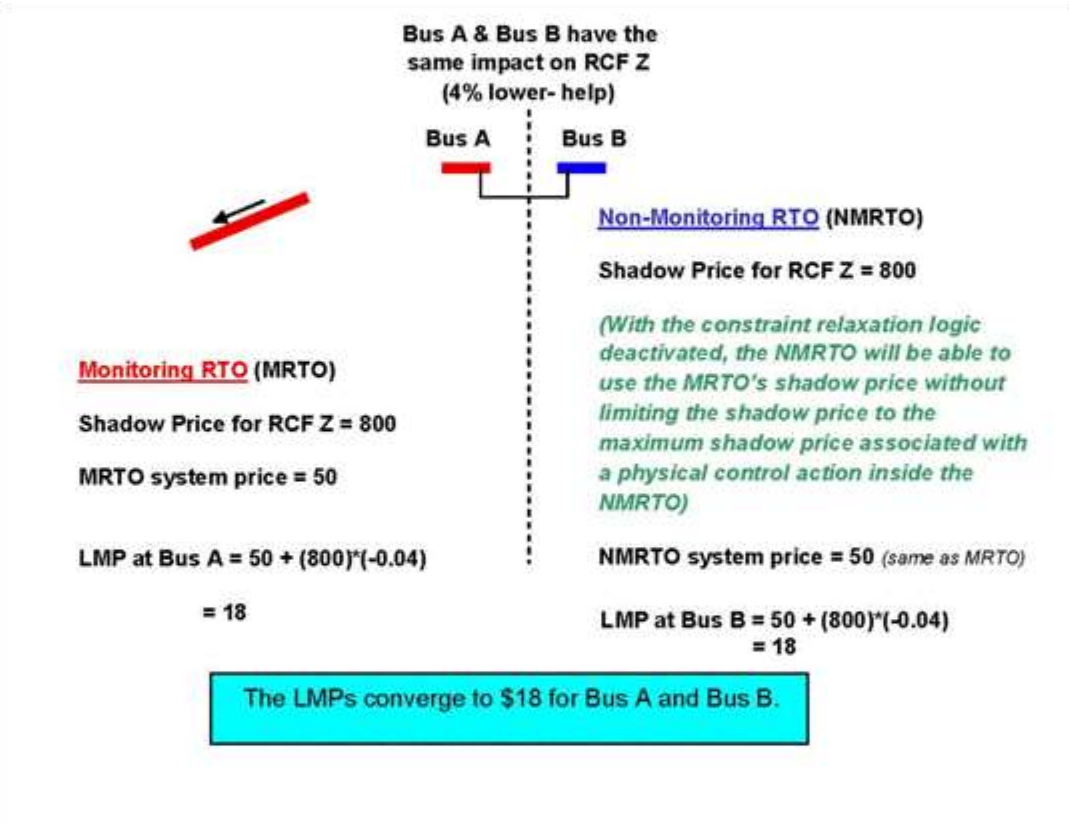
Under the normal M2M implementation, sufficient redispatch for a M2M Flowgate may be available in one RTO but not the other. When this condition occurs, in order to ensure a physically feasible dispatch solution is achieved, the RTO without sufficient redispatch will activate logic in its dispatch algorithm which redispatches all available generation in the RTO to control the M2M Flowgate to a “relaxed” limit. Then this RTO calculates the shadow price for the M2M Flowgate using the available redispatch which is limited by the maximum physical control action inside the RTO. Because the magnitude of the shadow price in this RTO cannot reach that of the other RTO with sufficient redispatch, unless further action is taken, there will be a divergence in shadow prices and the LMPs at the RTO border.

The example below illustrates how the LMPs at the RTO border diverge under this condition:



A special process is designed to enhance the price convergence under this condition. If the Non-Monitoring RTO cannot provide sufficient relief to reach the shadow price of the Monitoring RTO, the constraint relaxation logic will be deactivated. The Non-Monitoring RTO will then be able to use the Monitoring RTO's shadow price without limiting the shadow price to the maximum shadow price associated with a physical control action inside the Non-Monitoring RTO. With the M2M Flowgate shadow prices being the same in both RTOs, their resulting bus LMPs will converge in a consistent price profile.

The following example illustrates how the price convergence can occur:



This process also allows price convergence when the Non-Monitoring RTO has a higher shadow price than the Monitoring RTO.

8 Appropriate Use of the Market-to-Market Process

A subset of flowgates that meet the criteria as described in Section 1.1, impacted by market flows from the two RTOs' energy markets, will be subject to the M2M process and called M2M Flowgates. This subset will be controlled using M2M tools for coordinated redispatch and additionally will be eligible for M2M settlements.

In principle and as much as practicable, Parties agree that the goal is to control to the most limiting Flowgate using the actual Flowgate limit. The RTOs will record and exchange actual M2M Flowgate limits, the limit used to bind, and a reason for significant deviation.

There are times when either Party, acting as the Monitoring RTO, will bind a M2M Flowgate different from its actual limit. The Parties have agreed in subsections 8.1 through 8.4 of this Section 8 to the conditions under which M2M settlement will occur even though a limit to which the Monitoring RTO is binding (limit control) is less than its actual limit.

8.1 Qualifying Conditions for Market-to-Market Settlement:

8.1.1 **Purpose of Market-to-Market**. M2M was established to address regional, not local issues. The intent is to implement M2M coordination and settle on such coordination where both Parties have significant impact.

8.1.2 **Conditions Under Which Parties may Revise M2M Settlements**.

a. The Parties agree that upon reaching mutual agreement they will revise M2M settlements to minimize financial harm to either RTO that results from an error in the initiation, implementation, termination, or settlement of M2M coordination, including, but not limited to: Firm Flow Entitlements; calculated Market Flows; shadow price calculation; M2M Flowgate definition; and initiating coordination on a flowgate that does not qualify as a M2M constraint.

b. Further, the Parties have an obligation to timely and reasonably investigate potential uneconomic production so as to avoid M2M settlements that should not continue. Identification of uneconomic production by itself will not automatically trigger a M2M settlement adjustment; however, if a Party fails to timely and reasonably investigate and/or fails to take appropriate corrective action promptly when there is an indication of uneconomic production, and it is subsequently found that uneconomic production occurred, M2M settlements shall be adjusted, upon mutual agreement, with respect to those M2M Flowgates impacted by the identified unit(s), subject to the limitations set forth in Section 18.3.4.

c. This section shall not limit the requirements for after-the-fact review of M2M events or limit any available remedies as contemplated in Section 8.2.2 and Section 8.4.

8.1.3 **Use Market-to-Market Whenever Binding a M2M Flowgate**. The M2M process will be initiated by the Monitoring RTO whenever an M2M Flowgate is constrained and therefore binding in its dispatch.

8.1.4 **Most Limiting Flowgate**. Generally, controlling to the most limiting Flowgate provides the preferable operational and financial outcome. In principle and as much as practicable, M2M coordination will take place on the most limiting Flowgate, and to that Flowgate's actual limit (thermal, reactive, stability).

a. M2M events that involve the use of a limit control that is below 95% of the actual limit will be subject to an after-the-fact review, unless the lower limit was agreed to by the RTOs prior to the market-to- market binding event. The review will determine if normal market-to- market settlements are appropriate. If M2M settlements are determined by the Parties not to be appropriate, then settlements will not occur on the M2M Flowgate. Sufficient real-time and after-the-fact data will be exchanged to enable these reviews. The Parties may agree to change the trigger for review to a lower number for specific Flowgates, however, either Party may request review of specific instances that are bound above the established binding percentage.

8.1.5 **Substitute Flowgates**. The Parties agree that, if the use of substitute Flowgates is minimized and the ability to coordinate on the most limiting Flowgate in the very near term is enabled, there should be very few instances where M2M coordination occurs without resulting settlement.

a. Generally, M2M coordination without the normal market-to- market settlement will be limited to times when: (1) a substitute is used for a period in excess of that defined in Section 8.1.5 (b) (ii) below, or (2) a substitute Flowgate (whether M2M or non-M2M) is used and the most limiting Flowgate is later determined to fail the M2M tests.

b. Where the most limiting constraint (monitored/contingent element pair) is not a defined M2M Flowgate:

i. Parties will add the Flowgate definition and activate market-to-market coordination on that Flowgate (as opposed to a substitute) as soon as reasonably practicable; or

ii. A substitute Flowgate may be used for a short time (generally less than an hour) until it is possible to coordinate using the most limiting Flowgate. Parties will attempt to use either: (i) the most limiting M2M Flowgate or (ii) the most limiting Flowgate that is modeled by both Parties, in that order of preference. If possible, the Parties should use another Flowgate that is limiting. Optimal choices are Flowgates with the same or very similar Market Flow impacts (sensitivities) resulting in a very similar redispatch and M2M settlement.

c. A substitute Flowgate can be used in the M2M process pending the outcome of the coordinated Flowgate tests. The substitute Flowgate will be utilized only until the actual constraint can be entered in both the Monitoring and Non-Monitoring RTO systems as an M2M Flowgate. M2M settlement is dependent on the outcome of the coordinated Flowgate tests on the actual constraint and the RTO requesting the use of a substitute Flowgate will do so at its own risk that M2M settlement may not occur.

d. A substitute M2M Flowgate will not be used to control for another constrained M2M Flowgate except in very limited circumstances and only where there is prior mutual agreement between MISO and SPP to do so. Mutual agreement is established only when it has been communicated and logged by the control center operators that the coordinated Flowgate is not the most limiting (i.e., it is a substitute Flowgate).

e. A substitute M2M Flowgate will not be used to control for a non-M2M Flowgate that has failed the Flowgate study or has not been entered into the study process.

f. Ay use of substitute Flowgate should be clearly logged by both RTO operators with the actual start time, the actual end time and the reason for using a substitute Flowgate.

g. If the Monitoring RTO requests TLR on an M2M Flowgate but has not initiated the M2M process and is not binding its market for that Flowgate, the Non-Monitoring RTO is not required to bind its market for that Flowgate in order to meet the Non-Monitoring RTO’s TLR relief obligation. It will be assumed that the Monitoring RTO is binding its market for the actual constraint and that the actual constraint is already active in the M2M process (if the actual constraint is an M2M Flowgate).

8.1.6 **Operating Guides** that refer to M2M operation do so under the assumption that the Flowgates for which M2M operations take place are, or are expected to be, constrained. Operating Guides are written by operators and are not intended to result in settlement not otherwise contemplated by the JOA or this ICP. Safe Operating Mode (SOM) is reserved for abnormal conditions when existing operating guides and normal tool sets are not sufficient to manage abnormal operating conditions. After declaring SOM, operator actions may include using market-to- market tools in addition to direct dispatch. Operators may choose to use substitute M2M Flowgates with the dispatch tools to maintain reliable operations. Settlement determination will occur during the After-the-Fact Review set forth in Section 8.4 below. Generally, settlement for M2M coordination that takes place after SOM is declared will apply if the settlement would apply under normal conditions.

8.2 Specific Conditions Applicable to Section 8.1.4 (Most Limiting Flowgate)

8.2.1 Market-to-Market Events Not Requiring an After-the-Fact Review

The MISO and SPP operators will model all M2M Flowgates facilities with actual limits in their respective EMSs. The MISO EMS model uses design thermal limits of equipment. The MISO limits are updated in UDS/RTBM following contacts with Transmission Owners prior to binding. The MISO and SPP operators will control the flows on these M2M Flowgates in their respective UDS/RTBM at a binding percentage that is 95% or greater of the M2M Flowgate actual limit.

8.2.2 Market-to-Market Events Requiring an After-the-Fact Review

All M2M events that involve the use of a limit control that is below 95% of the actual limit will be subject to an after-the-fact review to determine whether this was an appropriate use of the M2M process as determined by this Agreement and is subject to normal M2M settlement. The following criteria will be used in making such a determination:

8.2.2.1 **Reducing the UDS/RTBM Binding Percentage to Provide Necessary Constraint Control**:

a. A reduced UDS/RTBM binding percentage below 95% of the actual facility limit can be applied to an M2M Flowgate by the Monitoring RTO provided the monitored element (for the defined contingency condition) of the M2M Flowgate meets the following conditions:

i. The monitored element is, or is expected to be, over its actual limit (post contingency if applicable) and the UDS/RTBMs are not providing the desired relief.

ii. Transient system behavior necessitates controlling the M2M Flowgate to a target between 95% and 100% and providing some margin. To achieve this, in some instances, the UDS/RTBM percentage may need to be below 95%.

iii. The limit for the monitored element changes due to equipment switching out of service. For instance the actual limit of a line is reduced when one of the breakers in a breaker-and-half configuration is out of service, or only one parallel transformer remains in service at one of the line end terminals.

iv. A constraint with a very high loading volatility such that loading is expected to exceed 100% of the actual limit, even when the UDS/RTBM binding percentage is significantly below that value.

b. The reduced UDS/RTBM binding percentage should only be applied for the time duration necessary to manage the initiating condition and shall be returned to normal as soon as possible.

c. Each time the Monitoring RTO reduces the binding limit control of an M2M Flowgate below 95% for an actual or relevant post contingency overload, the Monitoring RTO operator will make a best effort to notify the Non- Monitoring RTO operator of the new limit control, the reason for the change, and when the limit control is expected to be returned to normal (if known). Both RTO operators will log the event. This notification only applies to an operating condition causing a limit control change; it does not apply to the use of temperature adjusted limits, voltage limits or stability limits implemented as flow limits.

i. A limit reported by a Transmission Owner on the operating day shall require an accompanying reason. If the limit is set to control for underlying facilities, this shall be called out specifically. Any reason other than those specifically called out herein shall be reported.

d. The Monitoring RTO will operate to the most conservative limit when there are conflicting results between two different EMSs (either another RTO EMS or a Transmission Owner EMS) unless the reason for the difference is known.

8.2.2.2 **Reducing the UDS/RTBM Binding Percentage of a M2M Flowgate for Prepositioning**

a. In some conditions system flows are expected to change quickly due to load pick-up, planned, and emergency outages, and the

UDS/RTBM may not be accurately predicting a resulting overload on the M2M Flowgate in the near future.

When a reduction in binding percentage is initiated by the operator to mitigate expected impacts on an M2M Flowgate from a planned outage, that action shall be taken to prepare the system consistent with the time submitted on the outage ticket or as revised by the equipment operator. This reduction should be for as short a time as practicable but may be extended if the outage is delayed. If possible, initiating the reduction in binding percentage shall be delayed until the outage begins.

b. M2M Flowgates may be de-rated for a short period of time to pre-position the system for an expected change. These expected changes can include:

   i. Change in unit status (anticipated as part of an upcoming outage, reacting to an imminent emergency outage, or change in commitment if the unit for which the commitment was changed cannot be adequately ramped to allow normal redispatch to manage any resulting constraints).

   ii. Transmission system topology change (either anticipated event or as part of an upcoming planned outage). In this case, every effort shall be made to add the expected constraint to the systems and bind on the expected constraint instead of using a substitute Flowgate.

   iii. Increase or decrease in wind generation output.

c. Reducing the limit to pre-position the system will be considered an appropriate use of M2M tools but subject to settlement adjustment for substitute M2M Flowgates applying a hold harmless approach discussed in the After the Fact Review process set forth in Section 8.4 below. The time duration of such events shall be limited to that necessary to pre-position to avoid excessive impacts on market prices.

8.3 Specific Conditions Applicable to Section 8.1.6 (Operating Guides)

8.3.1 All op guides are subject to review by MISO and SPP through which either RTO can request removal of a reference to the M2M process. Where reference to the M2M process has been removed and not replaced by alternate congestion management actions, the use of SOM will be added to the op guide if it is not already included in the op guide. Before modifying existing op guides, MISO and SPP will agree to a mechanism to manage congestion that will avoid the need for repeated SOM declarations on the same constraint.

8.3.2 In the event of severe abnormal system conditions, such as storm damage to critical facilities, the Parties shall meet as soon as practicable to agree upon the response, which shall be incorporated into a temporary operating guide.

8.4 Capping FFE to the SOL of a M2M Flowgate

8.4.1 The Parties agree that the FFE of the Non-Monitoring RTO shall be less than or equal to the flowgate rating used in the historic allocation calculations.

a. The FFE of the Non-Monitoring RTO used in final M2M Settlement shall not exceed the flowgate rating used by the historic allocation process to determine the FFE.

b. The Parties agree to request that the raw FFE (value before capping) of the NMRTO be capped by using raw FFE input data (no caps applied) and then by applying an after the fact cap adjustment to the FFE (automatically or by manual adjustment) such that it does not exceed the flowgate rating in the historic allocation process.

8.5 <u>After-the-Fact Review to Determine Market-to-Market Settlement</u>

8.5.1 Based on the communication and data exchange that has occurred in real-time between the Monitoring RTO operator and the Non-Monitoring RTO operator, there will be an opportunity to review the limit change and the use of the M2M process to verify it was an appropriate use of the M2M process per this Agreement and good utility practice and subject to M2M settlement. The Monitoring RTO will initiate the review as necessary to apply these conditions and settlements adjustments.

a. A review will verify that the limit used in the M2M coordination represented the actual limit of the monitored element of the original Flowgate that has passed one of the M2M Flowgate Studies. The Monitoring RTO will archive and make available data (including all UDS/RTBM solutions) that supports the decision to change the M2M Flowgate limit. The Parties will mutually agree upon, and document in writing and post on the Parties’ websites, the data that should be exchanged and/or archived to meet this requirement, and shall retain the data for the period applicable to other data used to audit settlements inputs and market flow calculations under this agreement.

b. A review will verify the outcome of the M2M Flowgate Studies and whether the potential Flowgate passed one of the M2M Flowgate Studies by both the Monitoring RTO and the Non-Monitoring RTO. The Monitoring RTO uses M2M tools before a M2M Flowgate is approved at its own risk regarding M2M settlement. After the M2M Flowgate Studies are complete, if the Flowgate did not pass at least one of the studies conducted by the Monitoring RTO and at least one of the studies conducted by the Non- Monitoring RTO, then settlements will be adjusted as follows.

i. If the Non-Monitoring RTO's integrated market flows are below its Firm Flow Entitlement for the hour, there will be a normal M2M settlement with a payment from the Monitoring RTO to the Non- Monitoring RTO for the hour.

ii. If the Non-Monitoring RTO's integrated market flows exceed its Firm Flow Entitlement for the hour, there will be no M2M settlement for the hour.

iii. If the Monitoring RTO was requested to initiate the M2M process on the Monitoring RTO's Flowgate to assist the Non-Monitoring RTO, the Monitoring RTO will be held harmless as follows.

a. If the Non-Monitoring RTO's integrated market flows are below its Firm Flow Entitlement for the hour, there will be no market-to- market settlement for the hour.

b. If the Non-Monitoring RTO's integrated market flows exceed its Firm Flow Entitlement for the hour, there will be a normal market- to-market settlement with a payment from the Non-Monitoring RTO to the Monitoring RTO for the hour.

8.5.2 The Non-Monitoring RTO may request the Monitoring RTO to implement the M2M process on its behalf. There will be an after the fact review performed to determine whether this M2M event should be subject to settlement. If the review finds it is subject to settlement, the usual criteria will be applied. If the review finds it is not subject to settlement, the usual criteria will be applied except that the Monitoring RTO shall be held harmless.

a. If the Non-Monitoring RTO's integrated market flows are below its Firm Flow Entitlement for the hour, there will be no M2M settlement for the hour.

b. If the Non-Monitoring RTO's integrated market flows exceed its Firm Flow Entitlement for the hour, there will be a normal M2M settlement with a payment from the Non-Monitoring RTO to the Monitoring RTO for the hour.

8.5.3 A new M2M Flowgate shall be subject to a hold-harmless provision for the balance of the current operating day in which the M2M Flowgate is submitted for coordination by the Monitoring RTO as a result of a planned outage in the Monitoring RTO's system as provided below:

a) If the Non-Monitoring RTO's integrated market flows are below its Firm Flow Entitlement for the hour, there will be a market-to-market settlement with a payment from the Monitoring RTO to the Non-Monitoring RTO for the hour.

b) If the Non-Monitoring RTO's integrated market flows exceed its Firm Flow Entitlement for the hour, there will be no market-to-market settlement for the hour.

c) Notwithstanding the above provisions, these hold-harmless provisions shall not apply (i.e., a market-to-market settlement will occur) if the new M2M Flowgate was necessitated by an unplanned outage (forced, emergency, or urgent) that could not meet normal outage scheduling timeframes.

Nothing in this section is intended to restrict either Party's ability to submit new M2M Flowgates for coordination using the real-time market-to-market coordination procedures.

8.5.4 The settlement provisions, including exceptions, contained in Section 8.5.3 shall also apply for the next operating day when a new M2M Flowgate is submitted for coordination by the Monitoring RTO, as a result of a planned outage in the Monitoring RTO's system, subsequent to the cutoff for data submission of (i.e., the close of) the Non-Monitoring RTO's Day-Ahead market.

8.5.5 A new M2M Flowgate shall be subject to a hold-harmless provision for the balance of the current operating day in which the M2M Flowgate is submitted for coordination by the Monitoring RTO as a result of a planned outage in the Non-Monitoring RTO's system as provided below:

a) If the Non-Monitoring RTO's integrated market flows exceed its Firm Flow Entitlement for the hour, there will be a market-to-market settlement with a payment from the Non-Monitoring RTO to the Monitoring RTO for the hour.

b) If the Non-Monitoring RTO's integrated market flows are below its Firm Flow Entitlement for the hour, there will be no market-to-market settlement for the hour.

c) Notwithstanding the above provisions, these hold-harmless provisions shall not apply (i.e., a market-to-market settlement will occur) if the new M2M Flowgate was necessitated by an unplanned outage (forced, emergency, or urgent) that could not meet normal outage scheduling timeframes.

d) Notwithstanding the above provisions, these hold-harmless provisions shall not apply (i.e., a market-to-market settlement will occur) if the planned outage had been previously coordinated with the Monitoring RTO but the M2M Flowgate was submitted after the beginning of the current operating day by the Monitoring RTO.

Nothing in this section is intended to restrict either Party's ability to submit new M2M Flowgates for coordination using the real-time M2M coordination procedures.

8.5.6. The settlement provisions, including exceptions, contained in Section 8.5.5 shall also apply for the next operating day when a new M2M Flowgate is submitted for coordination by the Monitoring RTO as a result of a planned outage on the Non-Monitoring RTO's system, subsequent to the cutoff for data submission of (i.e., the close of) the Monitoring RTO's Day-Ahead market.

8.6 <u>M2M Data Exchange</u>

8.6.1 A data exchange will be established. Parties shall mutually agree upon data, format and frequency of exchanges. The data exchange must be updated to include, but not be limited to, the following data as soon as practicable if requested by either Party.

a. actual Flowgate SE/SA flow from the approved case,

b. UDS/RTBM solution %,

c. operator entered binding %,

d. actual Flowgate limit, and

e. shadow price.

Appendix A: Definitions

Any undefined, capitalized terms used in this ICP shall have the meaning: (i) provided in the Joint Operating Agreement between SPP and MISO, or in the CMP, or (ii) given under industry custom and, where applicable, in accordance with good utility practices.

Monitoring RTO	The RTO that has the primary responsibility for monitoring and control of a specified M2M Flowgate
Non-Monitoring RTO	The RTO that does not have the primary responsibility for monitoring and control of a specified M2M Flowgate, but does have generation that impacts that Flowgate
Effective Limit	A limitation on a transmission facility used as an input to the UDS/RTBM Security-Constrained Economic Dispatch study run
Firm Flow	The estimated impacts of firm Network and Point-to-Point service on a particular M2M Flowgate
Firm Flow Entitlement	The firm flow entitlement (FFE) represents the net allocation on M2M Flowgates used in the M2M settlement process. The FFE is determined by taking the forward allocation (using 0% allocations) and reducing it by the lesser of the two day-ahead allocation in the reverse direction (using 0% allocations) or the generation-to-load impacts in the reverse direction (down to 0%). The generation-to-load impacts in the reverse direction come from the day-ahead allocation run. The forward allocation comes from the day-ahead network and native load (DA NNL) calculation. The FFE may be positive, negative or zero.
Flow Relief	The reduction in the MW flow on an M2M Flowgate that is caused by the generation redispatch as a result of the binding transmission constraint
Market Flow	The flow in MW on an M2M Flowgate that is caused by all generation deliveries to load in the RTO footprint
Proxy Bus	Each RTO's representation of a Settlement Location for the neighboring RTO such that an LMP is calculated at that location to settle import schedules, export schedules, or through schedules involving the neighboring RTO.
Reciprocal Coordinated	A Coordinated Flowgate for which Reciprocal Entities have

Flowgate (RCF)	generation that has a GLDF on the flowgate at or above the NERC approved threshold (currently, 5% or greater)
Requesting RTO	RTO that is requesting an increase in their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Requesting RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time.
Responding RTO	RTO that is responding to a request to reduce their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Responding RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time.
UDS/RTBM	Security constrained, economic dispatch software used to determine dispatch instructions to resources in a Party's market area
M2M Flowgate	Has the definition as defined in Section 1 of this Attachment 2
M2M Flowgate Studies	M2M Flowgate Studies consist of the coordinated flowgate tests defined in Section 3.2.1 of the Congestion Management Process and the significantly impacted flowgate tests defined in Section 1.1.3 of this Attachment 2.

ATTACHMENT 3

Emergency Energy Transactions

SPP or MISO may, from time to time, have insufficient Operating Reserves available to their respective systems, or need to supplement available resources to cover sudden and unforeseen circumstances such as loss of equipment or forecast errors. Such conditions could result in the need by the Party experiencing the deficiency to purchase Emergency Energy for Reliability reasons.

The purpose of this Attachment is to allow for the exchange of Emergency Energy between the Parties during such times when resources are insufficient and commercial remedies are not available. The offer to provide Emergency Energy shall be available only when the Party experiencing the deficiency has declared an Energy Emergency Alert, Level Alert 2 or higher, as defined in Attachment 1 of NERC Standard EOP-011-1, or as defined in a subsequent revision of such Standard.

1.0: CHARACTERISTICS OF THE POWER AND ENERGY

Unless otherwise mutually agreed, all power and energy made available by the delivering Party shall be three phase, 60 Hz alternating current at operating voltages established at the Delivery Point in accordance with system requirements and appropriate to the Interconnection.

2.0: NATURE OF SERVICE

2.1 SPP, to the maximum extent it deems consistent with:

(a) the safe and proper operation of its own system,
(b) the furnishing of dependable and satisfactory services to its own customers, and
(c) its obligations to other parties, including the terms and conditions of the SPP Tariff,

shall make available to the MISO energy market Emergency Energy from available generating capability in excess of its load requirements up to the transfer limits in use between the two Balancing Authority Areas.

SPP shall refer to all Emergency Energy transactions as being sold:

(a) “Recallable” where such a delivery could reasonably be expected to be recalled if SPP needed the generation for a deployment of reserves or other system Emergency; or

(b) “Non-Recallable” where SPP would normally be able to continue delivering the Emergency Energy following a reserve deployment.

The Parties shall use reasonable efforts to ensure that an Emergency Energy transaction continues only until it can be replaced by a commercial transaction.

2.2 MISO, to the maximum extent it deems consistent with:

(a) the safe and proper operation of its own Transmission System,
(b) the furnishing of dependable and satisfactory services to its own customers, and
(c) its obligations to other parties, including the terms and conditions of the MISO Tariff,

shall make available to SPP Emergency Energy from available generating capability in excess of its load requirements up to the transfer limits in use between the two Balancing Authority Areas.

MISO shall refer to all Emergency Energy transactions as being sold:

(a) "Recallable" where such a delivery could reasonably be expected to be recalled if MISO needed the generation for a deployment of reserves or other system Emergency; or

(b) "Non-Recallable" where MISO would normally be able to continue delivering the Emergency Energy following a reserve deployment.

The Parties shall use reasonable efforts to ensure that an Emergency Energy transaction continues only until it can be replaced by a commercial transaction.

2.3 In the event one Party is unable to provide Emergency Energy to the other Party when needed, but there is energy available from a third party Balancing Authority, delivery of such Emergency Energy will be facilitated to the extent feasible.

3.0: RATES AND CHARGES

3.1 All Emergency Energy transactions shall be billed based on scheduled deliveries.

3.2 All rates and charges associated with Emergency Energy shall be expressed in funds of the United States of America.

3.3 MISO and SPP agree that the charge for Emergency Energy delivered by one Party to the other Party shall be as defined below.

The delivering Party shall be allowed to include, in the total price charged for Emergency Energy, all costs incurred in the delivery of Emergency Energy to the Delivery Point, and the receiving Party shall be responsible for all costs at and beyond the Delivery Point.

Direct Transaction

The charge for Emergency Energy supplied by delivering Party in any hour to the receiving Party shall be calculated using the following two-part formula. The first part of the formula calculates the energy portion of the charge and the second part incorporates any transmission charges incurred by the delivering Party to deliver the Emergency Energy to the Delivery Point. In the case of SPP as the delivering Party, the cost of the energy portion shall be the greater of 150% of any applicable Locational Marginal Price ("LMP") at the point(s) of delivery to provide the Emergency Energy, or $100/MWHr. In the case of MISO as the delivering Party, the cost of the energy portion shall be the greater of 150% of the LMP at the point(s) of exit at the bus or buses at the border of the delivering Party's market, or $100/MWHr.

Energy Portion for an hour =

(Emergency Energy supplied in the hour in MWHr) **times**
(delivering Party's cost of such energy in $/MWHr)

Transmission Charge to Delivery Point (if applicable) =

The actual ancillary services (including delivering Party's market charges applicable to export schedules) and transmission costs incurred by the delivering Party in delivering such Emergency Energy to the Delivery Point pursuant to the delivering Party's Tariff or the equivalent thereof, or costs incurred pursuant to the transmission tariff of any transmission service provider, including the receiving Party.

Total Charge for Emergency Energy supplied in any hour =

The sum of the Energy Portion for an hour and the Transmission Charge for that same hour.

A Party requesting Emergency Energy under this Section is obligated to pay for the Emergency Energy in the amount requested, times a minimum period of one clock hour, once the delivering Party has initiated the redispatch of generation in the delivering Party's energy market or dispatch order, so that the energy will be made available at the time requested to the receiving Party at the Delivery Point.

Transaction from Third Party Supplier

The charge for Emergency Energy supplied to the receiving Party from a third party through the delivering Party's system shall be calculated using the following two-part formula. The first part of the formula calculates the energy portion of the charge and the second part incorporates any transmission charges incurred by the delivering Party to deliver the Emergency Energy to the Delivery Point. The delivering Party's cost for Emergency Energy shall be the cost that the third-party supplier charges the delivering Party or as otherwise stated in an agreement between receiving Party and the third-party supplier.

Energy Portion for an hour =

(Emergency Energy supplied in the hour in MWHr) **times**
(Third-party Supplier's charge for such energy in $/MWHr)

Transmission Charge to Delivery Point (if applicable) =

The actual ancillary service costs (as applicable), transmission costs and all other applicable costs attributable to such transactions incurred by the delivering Party in delivering such energy to the Delivery Point pursuant to the delivering Party's Tariff or the equivalent thereof, or costs incurred pursuant to the transmission tariff of any transmission service provider, including the receiving Party.

Total Charge for Emergency Energy supplied in an hour =

The sum of the energy portion for an hour and the transmission charge for that same hour.

A Party requesting Emergency Energy under this Attachment is obligated to pay the Transmission Charge, times a minimum period of one clock hour, once the delivering Party has entered the necessary schedules in the delivering Party's system.

4.0: MEASUREMENT OF ENERGY INTERCHANGED

All Emergency Energy supplied at the Delivery Point shall be metered. The delivering Party shall be responsible for the actual losses as a result of delivery to the delivery Point and the receiving Party shall be responsible for all losses from the delivery Point.

5.0: BILLING AND PAYMENT

5.1 Billing for, and payment of, all charges incurred pursuant to this Attachment shall be pursuant to Section 16.2 of the Joint Operating Agreement of which this Attachment is a part.