Coordination and Operating Agreement
Between the
Midcontinent Independent System Operator, Inc.
And
Minnkota Power Cooperative, Inc.

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Coordination and Operating Agreement
Between the
Midcontinent Independent System Operator, Inc.
And
Minnkota Power Cooperative, Inc.

ARTICLE I - RECITALS

This Coordination and Operating Agreement ("Agreement") dated this _15th___ day of__July____________, 2015, by and between Minnkota Power Cooperative, Inc. ("Minnkota") a Minnesota cooperative corporation having a place of business at 1822 Mill Road, Grand Forks, North Dakota, 58208 and the Midcontinent Independent System Operator, Inc. ("MISO"), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032. Minnkota and MISO may be individually referred to herein as "Party" or collectively as "Parties".

WHEREAS, Minnkota is a member-owned generation and transmission cooperative that provides wholesale generation and transmission services to its customers and interconnected member electric systems in the States of Minnesota and North Dakota;

WHEREAS, Minnkota is a NERC registered Transmission Service Provider, and maintains an Open Access Transmission Tariff for the purpose of providing open access transmission service, even though it is not subject to FERC jurisdiction with regard to the rates, terms and conditions of service of its tariff;

WHEREAS, MISO is a FERC approved Regional Transmission Organization that provides operating and reliability functions in portions of the United States and Canada, administers the MISO Tariff for transmission and other services on its grid, and operates markets to supply operating reserves, and to facilitate day-ahead and real-time energy transactions and financially firm transmission rights; and

WHEREAS, the Minnkota transmission system is highly integrated at various points with the transmission facilities owned by Transmission Owning Members of MISO, and which facilities constitute the MISO Transmission System; and

WHEREAS, pursuant to a settlement agreement entered into by the Parties and Otter Tail Power Company in 2005, filed on April 1, 2005 in FERC Docket Nos. EL04-104-000, ER04-691-000 and ER04-106-002 ("2005 Settlement Agreement With Otter Tail Power"), a settlement agreement entered into by the Parties and Minnesota Power in 2005, filed on April 1, 2005 in FERC Docket Nos. EL04-104-000, ER04-691-000 and ER04-106-002 ("2005 Settlement Agreement With Minnesota Power"), and a settlement agreement entered into by the Parties and Otter Tail Power Company and Montana-Dakota Utilities Company and NorthWestern Energy in 2005, filed on April 1, 2005 in FERC Docket Nos. EL04-104-000, ER04-691-000 and ER04-106-002 ("2005 Settlement Agreement With Otter Tail Power Company and Montana-Dakota Utilities Company and NorthWestern Energy"), it was agreed that Minnkota has sufficient generation and transmission capacity to serve its load without the use of the MISO Transmission System, and the agreements establishing Minnkota's transmission rights were deemed to be excluded from the MISO Markets; and

WHEREAS, the 2005 Settlement Agreement With Otter Tail Power was amended in 2008, filed on November 17, 2008 in FERC Docket No. ER09-300-000 ("2008 Amended Settlement Agreement With Otter Tail Power"), by the mutual consent of the parties to accommodate Minnkota's desire to remain within the MISO Balancing Authority Area that began operations with the initiation of the MISO Energy and Operating Reserve Markets on January 6, 2009; and

WHEREAS, the 2008 Amended Settlement Agreement With Otter Tail Power continued to recognize that Minnkota owns or has rights to sufficient generation and transmission capacity to serve its load without the use of the MISO Transmission System, but provided that Minnkota would be invoiced as a Carved Out GFA for certain MISO Tariff charges to reflect its participation in the MISO markets and its access to operating reserves in the MISO Balancing Authority Area; and

WHEREAS, in accordance with good utility practice and the intent of the Settlement Agreements, as such term is defined in this Agreement, the Parties desire to establish procedures for coordinated operations and exchange of information, and to acknowledge existing and future operating protocols to assure the continued reliability and efficient use of their transmission systems, and MISO's market operations; and

WHEREAS, the Parties desire to establish the way that MISO congestion management processes will be used on the transmission systems of the Parties, including allocation sharing on the Manitoba Hydro Export Interface and other flowgates on the transmission systems of the Parties; and

WHEREAS, the Parties desire to establish agreement on how Minnkota schedules transactions involving the transmission system within and outside of the MISO Balancing Area, and the applicability of MISO fees for these transactions; and

WHEREAS, Minnkota has consented to the establishment of transmission capacity sharing on the Bison-Maple River 345 kV line and wishes to document the rights of the Parties under such an arrangement.

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

ARTICLE II - ABBREVIATIONS, ACRONYMS AND DEFINITIONS

Section 2.1 Abbreviations and Acronyms.

2.1.1 "AFC" shall mean Available Flowgate Capability as the term is defined by NERC.
2.1.2 "ATC" shall mean Available Transfer Capability as the term is defined by NERC.
2.1.3 "CBM" shall mean Capacity Benefit Margin.
2.1.4 "CIM" shall mean Common Information Model.
2.1.5 "EFOR" shall mean Equivalent Forced Outage Rate.
2.1.6 "EMS" shall mean the Energy Management Systems utilized by the Parties to manage the flow of energy within their regions.
2.1.7 "FERC" shall mean the Federal Energy Regulatory Commission or any successor agency thereto.
2.1.8 "FTP" shall mean the standardized file transfer protocol for data exchange.
2.1.9 "ICCP/ISN" shall mean those common communication protocols adopted to standardize information exchange.
2.1.10 "IDC" shall mean the Interchange Distribution Calculator used for identifying and requesting congestion management relief.
2.1.11 "IDCWG" shall mean the Working Group established to provide advice on the IDC.
2.1.12 "LBA" shall mean Otter Tail Power Company or other entity providing Local Balancing Authority services to Minnkota, as the term Local Balancing Authority is defined in the MISO OATT.
2.1.13 "MMWG" shall mean the NERC working group that is charged with multi-regional modeling.
2.1.14 "MW" shall mean megawatt of power.
2.1.15 "MWh" shall mean megawatt hour of energy.
2.1.16 "MVP" shall mean Multi-Value Projects as defined in the MISO OATT.
2.1.17 "NERC" shall mean the North American Electricity Reliability Corporation or its successor organization.
2.1.18 "OASIS" shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet.
2.1.19 "OATI" shall mean the entity that has been retained by the IDC Association, or successor organization, to maintain the IDC system.
2.1.20 "OATT" shall mean the applicable Open Access Transmission Tariff.
2.1.21 "OMTA" shall mean out-of-the market transmission agreements to which Minnkota is a party and which are the subject of the Settlement Agreements.
2.1.22 "PMAX" shall mean the maximum generator real power output reported in MWs on a seasonal basis.
2.1.23 "PMIN" shall mean the minimum generator real power output reported in MWs on a seasonal basis.
2.1.24 "QMAX" shall mean the maximum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.25 "QMIN" shall mean the minimum generator reactive power output reported in MVARs at full real power output of the unit.
2.1.26 "RCF" shall mean Reciprocal Coordinated Flowgate.
2.1.27 "RTO" shall mean Regional Transmission Organization.
2.1.28 "SDX System" shall mean the system used by Reliability Coordinators to exchange system data.
2.1.29 "TLR" shall mean the Transmission Loading Relief Procedures used by Reliability Coordinators in the Eastern Interconnection to manage congestion.
2.1.30 "TRM" shall mean the Transmission Reliability Margin, which is 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.
2.1.31 "TTC" shall mean Total Transfer Capability.

Section 2.2 Definitions.

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/ATC. The "a" multiplier is applied to TRM in the planning horizon to determine non-firm AFC/ATC. The "b" multiplier is applied to TRM in the operating horizon to determine non-firm AFC/ATC. 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 "Administrative Fees" shall mean those MISO tariff charges associated with administering MISO and the MISO Market, in effect at the time the charge is incurred and generally applicable to participants in the MISO Market (other than Market Charges, MVP charges and Transmission Service Charges), associated with transactions in the MISO Energy and Operating Reserve Markets including, without limitation and for the purpose of illustration, Schedule 10 – ISO Cost Recovery Adder, Schedule 17 – Energy Market Support Administrative Service Cost Recovery, and Schedule 23 - Recovery of Schedule 10 and Schedule 17 Costs from GFAs.

2.2.3 "Agreement" shall have the meaning stated in the preamble.

2.2.4 "Available Flowgate Rating" shall have the meaning stated in Section 5.1.4.

2.2.5 "Balancing Authority Area" shall mean the collection of generation, transmission, and load within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

2.2.6 "Confidential Information" shall have the meaning stated in Section 18.1.1.

2.2.7 "Congestion Management Process" means that document which is Attachment 2 hereto as it exists on the Effective Date and as it may be amended or revised from time to time, and which has been approved by the Congestion Management Process Working Group or as otherwise agreed to by the Parties.

2.2.8 “Coordinated Flowgates” shall have the meaning stated in Section 6.1.

2.2.9 “Coordinated Operations” means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.10 “Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.11 “Effective Date” shall have the meaning stated in Section 18.4.

2.2.12 “Firm Flow” shall mean the estimated impacts of firm transactions under Network and Point-to-Point service on a particular Coordinated Flowgate.

2.2.13 “Firm Flow Limit” shall mean the maximum value of firm flows an entity can have on a Reciprocal Coordinated Flowgate.

2.2.14 “Flowgate” shall mean a representative modeling of a facility or group of facilities that may act as a constraint to power transfer on the bulk transmission system.

2.2.15 “Freeze Date” shall mean April 1, 2004, as that date is applied in the Congestion Management Process.

2.2.16 "Historic Firm Flow" shall have the meaning given that term in the Congestion Management Process, Attachment 2 to this Agreement.

2.2.17 “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.

2.2.18 “Intermittent Generation” shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.19 “MISO Market” shall mean the MISO Energy and Operating Reserve Markets.

2.2.20 "Market-Based Operating Entity" shall have the meaning given that term in the Congestion Management Process, Attachment 2 to this Agreement.

2.2.21 “Market Charges” shall mean those MISO tariff charges, in effect at the time the charge is incurred and generally applicable to participants in the MISO Market (other than Administrative Fees, Transmission Service Charges, and MVP charges), associated with transactions in the MISO Energy and Operating Reserve Markets including, without limitation and for the purpose of illustration, Day-Ahead Asset Energy Amount, Day-Ahead Revenue Sufficiency Guarantee Distribution Amount, Real-Time Asset Energy Amount, Real Time Revenue Neutrality Uplift Amount, and Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount. A description of all charge types and their calculation can be found in the MISO Business Practices Manual, BPM-005, “Market Settlements” and the associated MS-OP-029, “Market Settlements Calculation Guide.”

2.2.22 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources within a Market-Based Operating Entity’s market (excluding tagged transactions).

2.2.23 “Minnkota” has the meaning stated in the preamble of this Agreement.

2.2.24 “MISO” has the meaning stated in the preamble of this Agreement.
2.2.25 “Notice” shall have the meaning stated in Section 18.10.

2.2.26 “Off-System” shall mean any transmission system for which neither of the Parties is the Transmission Service Provider, as that term is defined by NERC.

2.2.27 “OMTA Load Cap” shall mean the maximum Minnkota load level that is eligible for OMTA treatment, indicative of the maximum load that Minnkota can serve through its own transmission system and other transmission systems which Minnkota has the right to use pursuant to one or more OMTAs.

2.2.28 “OMTA Schedules” shall mean schedules submitted for the purpose of documenting Minnkota’s usage of its own transmission system or other transmission systems which Minnkota has the right to use pursuant to one or more OMTAs.

2.2.29 “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.

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

2.2.31 “Reciprocal Coordinated Flowgates” shall have the meaning stated in Section 6.1.

2.2.32 “Reciprocal Entity” shall mean a Party that coordinates the future-looking management of flowgate capacity in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.33 “Reliability Coordinator” (“RC”) shall mean that party approved by NERC to be responsible for reliability for a region.

2.2.34 "Reliability Coordination Service Agreement" ("RC Agreement") is that agreement, dated May 29, 2009, in effect between Minnkota and MISO which designates MISO as the RC for Minnkota.

2.2.35 "SCADA Data" shall mean the data that is generated by an energy management system which is used to monitor and control the transmission system.

2.2.36 "Settlement Agreements" shall mean the following agreements as defined in the recitals: the 2005 Settlement Agreement With Otter Tail Power, the 2005 Settlement Agreement With Minnesota Power, the 2005 Settlement Agreement With Otter Tail Power Company and Montana-Dakota Utilities Company and NorthWestern Energy, and the 2008 Amended Settlement Agreement With Otter Tail Power.

2.2.37 "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.

2.2.38 "Transmission Owner" shall mean any entity defined as such under the Minnkota OATT, or MISO OATT.

2.2.39 "Transmission Service Charges" shall mean the charges (other than Administrative Fees, Market Charges and MVP charges) assessed under a Party's OATT for the delivery of energy through the Party's transmission system.

Section 2.3 Rules of Construction.

Section 2.3.1 <u>No Interpretation Against Drafter.</u>

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 <u>Incorporation of Preamble and Recitals.</u>

The Preamble and Recitals of this Agreement are for reference only and are not incorporated into the terms and conditions of this Agreement.

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 Definition of Certain Words.

Abbreviations and uppercase words not specifically defined in this Agreement shall have the meaning given them in the MISO Tariff.

Section 2.3.5 NERC Reliability Standards.

Nothing in this agreement shall require a Party to take any action that is not, in its reasonably exercised discretion, in compliance with the applicable NERC Reliability Standards approved by FERC, as such standards may be revised from time to time.

Section 2.3.6 Scope of Application.

The Parties will perform this Agreement in accordance with its terms and conditions with respect to each transmission system for which each Party is registered with NERC as the Transmission Service Provider, and for which each Party administers transmission service in accordance with its respective transmission tariff.

Section 2.3.7 Headings.

The descriptive headings in this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

ARTICLE III - OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

Section 3.1 Overview

The Parties agree that Minnkota has sufficient generation, transmission facilities, and contract rights to serve its load without using MISO's system and that MISO is not providing transmission service to Minnkota when Minnkota is exercising its rights to use its own generation, transmission facilities, and contract rights to serve its load. The Parties also agree that, where Minnkota has sufficient transmission facilities and contract path rights to engage in transactions with non-MISO entities that are directly connected to Minnkota's system, Minnkota is not using MISO transmission service except as provided in Section 15.3.6 and Section 15.3.7 of this Agreement.

Section 3.2 Ongoing Review and Revisions.

The Parties have agreed to the coordination of their respective transmission systems and to the 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 transmission systems, relevant agreements, 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 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 affected requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time. No such revisions shall be effective except as provided in Section 18.11.

Section 3.3 Reliability Coordination Service

Minnkota agrees to take, and MISO agrees to provide, Reliability Coordination Service pursuant to the terms and conditions set forth in the RC Agreement while this Agreement is in effect.

Section 3.4 Minnkota as a Transmission Provider

Minnkota will continue to provide transmission service through an OASIS and perform the relevant Transmission Service Provider functions for which it is registered with NERC.

ARTICLE IV - EXCHANGE OF INFORMATION AND DATA

Section 4.1 Exchange of Operating Data.

To the extent that the data in this Section 4.1 is not being provided under other agreements as described in Section 4.3, the Parties will exchange the following types of data and information:

- Real-time and projected operating data;
- SCADA Data;
- EMS models;
- Planning information and models;
- Operations planning data;
- Transmission service coordination data;
- OMTA load cap submission; and
- Module E data submission.

Each Party shall make available the data identified above to the other Party with respect to all transmission facilities for which it administers transmission service and Balancing

Authority Areas for which it has responsibility on the Effective Date and during the term of this Agreement.

The Parties also shall exchange such information as the Market Monitor of MISO may request in order to facilitate monitoring in accordance with MISO's FERC-approved market monitoring plan.

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 from time to time agree. If a Party determines that an agreed format should be revised or an additional format adopted, a Party shall give Notice of the need for the additional format or revision and the Parties will jointly seek to complete development of the additional format or revision within thirty (30) days of such Notice or such longer period as the Parties may agree upon. The Parties agree that various components of the data exchanged under this Section 4 are Confidential Information and shall be subject to the requirements of Section 18.1 governing Confidential Information.

Section 4.1.1 Real-Time and Projected Operating Data.

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:

i. Status of the generating units each Party owns, operates or controls;

ii. Transmission line status;

iii. Real-time loads;

iv. Scheduled use of reservations;

v. TLR information, including calculation of Market Flows;

vi. Redispatch information, including the next most economical generation block to decrement/increment; and

vii. Real-time constraints.

(b) Projected operating information consists of:

i. Unit commitment/merit order for generators that each Party owns, operates or controls;

ii. Maintenance schedules for generators and transmission facilities that each Party owns, operates or controls;

iii. Firm purchase and sales;

iv. The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments that each Party owns, operates or controls; and

v. The planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units that each Party owns, operates or controls.

Section 4.1.2 <u>Exchange of SCADA Data.</u>

The Parties will exchange SCADA Data as follows.

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

(b) Each Party shall accommodate, as soon as practical, the other Party's requests for additional existing ICCP bulk transmission data points.

(c) Each Party shall respond, as soon as practical, to the other Party's requests for additional, unavailable ICCP bulk transmission data points.

(d) The Parties will comply with all governing confidentiality agreements executed by the Parties relating to ICCP 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;

Section 4.1.3 Planning Information and Models.

Minnkota will participate in the MISO quarterly model building process by providing updates and changes to the representation of its facilities in the MISO EMS model.

Section 4.1.4 Operations Planning Data.

The data in this Section 4.1.4 is being provided under other agreements as described in Section 4.3.

Section 4.1.4.1 - Generator Data:

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

Section 4.1.4.2 – Intermittent Generation:

- Accredited capacity;
- Planned maintenance;
- Whether aggregated generation or generation by piece of equipment; and
- Whether all output is tagged

Section 4.1.4.3 - Dynamic Schedules and Pseudo-Ties:

- List of dynamic schedules and pseudo-ties;
- Identification of pseudo-ties that are being used to move generation or load into the MISO Balancing Authority Area or out of the MISO Balancing Authority Area;
- Identification of dynamic schedules; and
- Requirements under Section 5.1.7.

Section 4.1.4.4 - List of Controllable Devices:

- Phase shifters;
- DC lines; and
- Back-to-back AC/DC converters.

Section 4.1.4.5 - Generation and Transmission Outages:

Each Party shall provide the other Party with projected status of generation availability over the next twelve (12) months utilizing the MISO outage scheduling system. 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.

Each Party will provide the other Party with the projected status of outage schedules for transmission facilities under its control over the next twelve (12) months or more if available utilizing the MISO outage scheduling system. 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.

(a) Generation outages that are planned or forecast shall be entered into the MISO outage scheduling system as soon as practicable after they are identified;

(b) Transmission outages that are planned or forecast shall be entered into the MISO outage scheduling system as soon as practicable after they are identified; and

(c) Notification of all forced outages of both generation and transmission resources shall be entered into the MISO outage scheduling system as soon as practical after they are identified.

Section 4.1.5 Transmission Service Coordination Data.

Upon the written request of a Party, the other Party shall provide the information specified in this Section 4.1.5 or any components thereof. Each request shall specify the information sought and the requested frequency upon which it would be provided. A Party receiving a request under this Section 4.1.5 shall provide the information promptly to the extent the information is available to the Party and to the extent that the Party has not already provided it to the requesting Party under this Agreement or other agreement. To the extent any of this data is also data exchanged in Section 4.1.2, it is considered Confidential Information.

Section 4.1.5.1 - Flowgates:

- Flowgate definitions including seasonal TTC, TRM, CBM, a & b multipliers;
- Flowgates to be added on demand;
- List of Coordinated Flowgates
- List of Flowgates to recognize when processing transmission service (if different than list of Coordinated Flowgates); and
- Requirements under Section 5.1.5.

Section 4.1.5.2 - Transmission Service Reservations:

- Daily list of all reservations, hourly increment of new reservations;
- List of reservations to exclude; and
- Requirements under Sections 5.1.2.

Section 4.1.5.3 – AFC Data:

Each Party currently meets and will continue to meet a minimum periodicity for calculating and posting AFCs. 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 two (2) days posted at a minimum, once per hour;

(b) Daily for days three (3) through thirty-one (31) posted at a minimum, once per day; and

(c) Monthly for months two (2) through sixteen (16) posted at a minimum, once per month.

Section 4.1.5.4 – Designated Network Resources:

- Network Integration Transmission Service Specifications;
- Designated Network Resource information;
- Indication of treatment as pseudo tie or dynamic/static schedules;
- Deemed ownership shares for jointly-owned units
- Rules for sharing output between joint owners; and
- Transmission arrangements.

Section 4.1.6 OMTA Load Cap Submission.

The Parties shall use the following procedures to request an increase in the OMTA Load Cap. If studies performed by Otter Tail Power Company ("OTP") and/or Minnkota demonstrate that an increase in the OMTA Load Cap is appropriate, or if Minnkota otherwise believes that an increase in the OMTA Load Cap is appropriate, Minnkota shall submit, in accordance with the Annual FTR Registration, Allocation and Auction timeline (available at: (https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=342) or such other site or documentation identified by MISO), the GFA Change Template (available at: (https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=902) or such other site or documentation identified by MISO) and such supporting documentation as may be requested by MISO and confirmed by OTP as the Transmission Owner in accordance with Section 3.10.7 ("Registration of Grandfathered Agreements") of MISO's Business Practices Manual No. 004 on "Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)" (or such other successor documentation and procedures that MISO may adopt). Such submission will include written concurrence from OTP as the Transmission Owner authorizing an increase in the OMTA Load Cap. MISO will promptly notify Minnkota and OTP, via email, of MISO's receipt of the GFA Change Template and supporting documentation. After reviewing the GFA Change Template and supporting documentation, MISO will notify Minnkota and OTP, via e-mail, of (a) any deficiencies that must be addressed to implement the requested increase in the OMTA Load Cap, or (b) MISO's acceptance of the request as valid. If MISO deems the request to be valid, the requested change will be reflected in the next Annual ARR Registration and Allocation.

Section 4.1.7 <u>Module E Data Submission</u>.

Minnkota, in accordance with the current version of Module E-1 of MISO's Tariff, agrees to submit annual forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data, as well as all applicable resource data required by MISO to satisfy the reliability obligation of the MISO footprint for each of the next ten Planning Years. Under the current version of Module E-1 (As Filed 6-13-2014), Minnkota will provide its demand forecasts that include (1) the annual Coincident Peak Demand within the Otter Tail Power (OTP) LBA in the MISO Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within the OTP LBA, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within the OTP LBA, for each Summer and Winter Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available annual Local Resource Zone Peak Demand within the OTP LBA in the Local Resource Zone (LRZ) for the upcoming Planning Year. All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the Module E Capacity Tracking (MECT) tool or other means described in the MISO Business Practices Manual (BPM) for Resource Adequacy, BPM-011, to submit the requisite information. Further details regarding the items required in the Demand forecasts submittal are in the MISO BPM for Resource Adequacy.

In addition, Minnkota will provide generating capability data through the MISO PowerGADS or other means described in Module E-1 and the MISO BPM for Resource Adequacy.

Additional Module E-1 coordination procedures are included in Section 12.3.

Section 4.2 Cost of Data and Information Exchange.

Each Party shall bear its own cost of providing information to the other Party pursuant to this Agreement.

Section 4.3 Data Already Provided.

Minnkota's obligations as specified in Sections 4.1.1, 4.1.2 and 4.1.4 shall be deemed satisfied by Minnkota providing data and information to MISO pursuant to its obligations under the RC Agreement and the 2008 Amended Settlement Agreement With Otter Tail Power.

ARTICLE V - ATC/AFC CALCULATIONS

Section 5.1 ATC/AFC Protocols

The Parties shall comply with the specific criteria for satisfying the requirements of this Article V as specified in the TTC/ATC/AFC Protocol which is Attachment 1 to this Agreement.

Section 5.1.1 Generation Dispatch Order.

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 that it owns, operates or controls. 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. Notwithstanding the foregoing, Minnkota shall not be required to provide information pursuant to this Section 5.1.1 to the extent that such information is already provided by the LBA.

Section 5.1.2 Transmission Service Requests.

Beyond the operating horizon, the impacts of existing transmission service requests are also necessary for the calculation of TTC and ATC/AFC for future time periods.

(a) Each Party will make available to the other Party actual transmission service request information for integration into each Party's TTC/ATC/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 ATC/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 the other Party's analysis.

Section 5.1.3 Calculated Firm and Non-firm Available Flowgate Capability

The Firm AFC is calculated with only the appropriate firm generation to load and 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 generation to load and firm and non-firm reservations (or interchange schedules) modeled.

The Parties agree to use the following procedure when reviewing requests for transmission service on their respective systems**:**

(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 loadings on its own flowgates as well as the loadings on the other Party's Flowgates.

(c) Each Party will limit approvals of transmission service reservations, including roll-over transmission service, so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the Parties.

Section 5.1.4 Available Flowgate Rating.

The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the flowgate. The flowgate rating is in units of megawatts. If the flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.

The Parties will exchange (seasonal, normal and emergency) Available Flowgate Ratings 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.

Section 5.1.5 Identification of Flowgates.

Each Party shall consider in its TTC and ATC/AFC determination process all flowgates: (i) that may initiate a TLR event, (ii) that are significantly impacted by either Party's transactions, or (iii) 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 Party that owns, operates or controls the facilities. The Parties in their AFC determination and transmission service processing efforts shall use the response factor cut-off that the owning/operating/controlling Party uses for its flowgates.

Section 5.1.6 Configuration/Facility Changes (for power system model updates).

Within sixty (60) days after the Effective Date of this Agreement, the Parties shall agree upon a mechanism that will be instituted between the Parties to ensure that all significant system changes are incorporated in each Party's TTC/ATC/AFC calculation model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the major changes that should be included in the TTC/ATC/AFC calculation models in a timely manner. This data exchange will occur no less often than prior to each peak load season.

In addition, the Parties agree to exchange TTC/ATC/AFC calculation models of their transmission systems within sixty (60) days of the Effective Date of this Agreement.

Section 5.1.7 Dynamic Schedule and Pseudo-Tie Flows.

Each Party agrees to provide the other Party with the actual amount and future projection of dynamic schedule and pseudo-tie flows commencing no later than sixty (60) days from the Effective Date of this Agreement. All dynamic schedule flows, pseudo-tie flows and tags will be submitted in accordance with NERC policy and procedures.

Section 5.1.8 Coordination of TRM Values.

Each Party shall make transmission capacity available for reserve sharing by including the 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 no less than annually.

Section 5.2 Transmission Capacity Sharing

The Parties agree that once Xcel Energy's Bison 345 kV substation has been constructed as an intermediate point on Minnkota's Jamestown - Buffalo – Maple River 345 kV line, the Bison-Maple River 345 kV segment of this line will be eligible for transmission capacity sharing in recognition of the Fargo area load-serving benefits provided by the Bison-Alexandria 345 kV line, which was commissioned on April 2, 2015. "Transmission capacity sharing" on this segment means that MISO and Minnkota will share their respective rights on the Bison-Maple River 345 kV line segment permitting either Party to use the segment as a transmission path for the purpose of granting transmission service. Either Party is permitted to schedule flows across this line segment without the need to reserve or schedule transmission service under the other Party's tariff. Minnkota reserves the right to declare the Bison-Maple River 345 kV line segment as an RCF if necessary to prevent the line from becoming oversubscribed. If the line becomes an RCF, Minnkota and MISO allocations will be combined as described in Article VI of this agreement.

Nothing in this agreement, however, shall give MISO the right to grant a request for interconnection to the Bison-Maple River 345 kV line.

Section 5.3 Data Already Provided

The Parties acknowledge that pursuant to the RC Agreement, Minnkota is already obligated to supply certain data and information to MISO. To the extent that such information is already provided to MISO through other means, Minnkota shall not be required to provide information pursuant to this Article V.

ARTICLE VI - RECIPROCAL COORDINATION OF FLOWGATES

Section 6.1 Reciprocal Coordination of Flowgates Operating Protocols.

The Congestion Management Process will be used to manage Flowgates on the Minnkota and MISO transmission systems on a comparable basis, subject to the limitations and exceptions stated in this Article VI. As used in this Article and the Congestion Management Process:

(a) "Coordinated Flowgate" or CF shall have the meaning it is given in the Congestion Management Process which is Attachment 2 to this Agreement.

(b) "Reciprocal Coordinated Flowgate" or RCF shall have the meaning it is given in the Congestion Management Process which is Attachment 2 to this Agreement and for which reciprocal coordination will occur.

For a Market-Based Operating Entity, CFs and RCFs will be subject to the requirements under the congestion management portion of the Congestion Management Process (Sections 4 and 5).

Minnkota shall have access to all information used by MISO in the determination and management of Flowgates involving Minnkota transmission facilities including models, input assumptions, and results of studies for its review.

Section 6.1.1 Scope of Coordination.

The extent of Minnkota's participation in the MISO Energy and Operating Reserve Markets, and the financial settlement of such participation, are governed by the terms and conditions of the Settlement Agreements and this Agreement: (i) Minnkota offers its generation and bids its load into the MISO Market; (ii) Minnkota's loads and resources are balanced as part of the MISO LBA in which Minnkota loads and resources reside; (iii) Minnkota makes Off-System sales of its generation using its own transmission to deliver the energy without additional charges for service under the MISO Tariff; (iv) Minnkota is a Market Participant but is not subject to MISO Transmission Service Charges and Market Charges when Minnkota generators are used to serve Minnkota load (including Off-System loads) using Minnkota's transmission system. To accommodate these unique arrangements, which benefit both Minnkota and MISO through Minnkota's participation in the MISO Market, the following adjustments have been made to MISO's market flow calculations and historic flowgate allocations:

(a) A combined MISO market flow that reflects all generators within the MISO Market (including Minnkota generators) being used to serve all load within the MISO Market (including Minnkota load).

(b) A combined MISO historic allocation that reflects MISO and Minnkota historic generation to load impacts and historic PTP impacts as of the freeze date utilized in the allocation process.

In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC/ATC and curtailment priorities for real-time operations applicable to the Party's Coordinated Flowgates (CFs). Additionally, each Party agrees to respect the combined allocation of both Parties defined by the reciprocal allocation process set forth in the Congestion Management Process currently in effect between MISO and Minnkota, Attachment 2 to this Agreement, when selling firm transmission service and in the assignment of market flow priorities except for the Manitoba Hydro Export (MHEX) Flowgate. For the MHEX Flowgate (U.S. portion), MISO and Minnkota will maintain separate allocations that will be used to sell firm transmission service across this interface in accordance with Section 6.3 of this Agreement.

Section 6.2 Application of Attachment 2

MISO and Minnkota agree to implement the Congestion Management Process identified in Attachment 2 to this Agreement, except as set forth in the following subsections for the purpose of implementing a methodology to determine joint MISO – Minnkota flows, limits and allocations rather than separate flows, limits and allocations, and as modified elsewhere in this Agreement.

Section 6.2.1 <u>Determination of Coordinated Flowgates</u>

In the application of Section 3 of Attachment 2, Minnkota flows shall be included with the flows of MISO when conducting the sensitivity studies for determining Coordinated Flowgates.

Section 6.2.2 <u>Determining Impacts on Coordinated Flowgates</u>

In the application of Section 4 of Attachment 2, Minnkota generators, load and tags that source or sink within the Minnkota area shall be included in the MISO Market Flow calculation when modeling the impact of MISO Market Flow on Coordinated Flowgates and for the purpose of determining a combined Firm Flow Limit on Coordinated Flowgates for MISO and Minnkota.

Section 6.2.3 <u>Management of Flows on Coordinated Flowgates</u>

MISO shall utilize its Unit Dispatch System (UDS) and Security-Constrained Economic Dispatch (SCED) in effect at the time to manage the flows on a Coordinated or Reciprocally Coordinated Flowgate attributable to MISO and Minnkota. The combined set of MISO and Minnkota generators will be redispatched on a least cost basis using SCED to manage MISO Market Flow on a Coordinated or Reciprocally Coordinated Flowgate. Minnkota will offer its resources into the MISO Markets and be economically dispatched through MISO's SCED under the same rules applicable to resources connected to MISO's Transmission System.

Section 6.2.4 Reporting Firm Flow Limits

In the application of Section 5 of Attachment 2, MISO firm and non-firm Limits reported to the IDC shall include the impacts of Minnkota generators serving Minnkota load.

Section 6.2.5 Limits and Allocations for RCFs

In the application of Section 6 of Attachment 2, the Historic Firm Flow calculation of Minnkota shall be included with the Historic Firm Flow calculation of MISO to determine a combined MISO-Minnkota firm allocation for RCFs. The combined MISO-Minnkota firm allocation will be used to establish a Firm Flow Limit for MISO Market Flows on all RCFs and will be used in the review of firm transmission service requests that impact RCFs. As between the Parties, Minnkota and MISO shall have access to the combined MISO-Minnkota firm allocations for RCFs pursuant to Section 6.7 of Attachment 2 on a first-come, first-served basis when reviewing firm transmission service requests.

The Parties acknowledge that designation of a transmission facility as an RCF does not, on its own, give a Party the right to grant transmission service across the facility. In order to grant transmission service, the Party must also have an uninterrupted transmission path between the Point of Receipt and Point of Delivery as specified in the transmission service request, and the transmission path must have a sufficient unreserved capacity that is equal to or greater than the amount of the transmission service being granted. The Parties agree that the MHEX interface is an exception to the path requirement described in this Section 6.2.5, in order to allow the Parties to grant transmission service across the MHEX interface in accordance with Section 6.3.

Section 6.3 Treatment of MHEX Flowgate.

The Parties agree to the designation of the MISO-owned/controlled and Minnkota-owned/controlled portions of the MHEX Flowgate as an RCF, pursuant to Section 3.2 of Attachment 2, notwithstanding that the Flowgate may not pass the sensitivity studies for Coordinated Flowgates, and notwithstanding the intention of the Parties to combine allocations on RCFs pursuant to Section 6.2.5. The Minnkota and MISO allocations of the MHEX Flowgate (U.S. portion) shall be defined by the Manitoba-U.S. Interface Transmission Capacity Rights Agreement. The combined MISO-owned/controlled and Minnkota-owned/controlled portions of the MHEX Flowgate will be subject to allocation sharing pursuant to Section 6.7 of Attachment 2, on a first-come, first-served basis when granting firm transmission service requests. Because the MHEX Flowgate will be treated as an RCF, non-firm transmission service may be provided by either Party on a first-come, first-served basis, up to the full capacity of the MHEX Flowgate, as long as the non-firm AFCs are positive. Each Party will make available to the other Party specific Transmission Service Request information that is used to establish the need for sharing of firm allocations. In the event that this Agreement is terminated during the term of service of a transmission service request granted by a Party using all or part of the other Party's MHEX Flowgate allocation in accordance with the terms of this Section 6.3 (whether such termination occurs during the initial term of such service or during a rollover term), then the other Party agrees to continue such service under the rates and terms of the open access transmission tariff, including any applicable rate schedules, governing the functional control of its transmission facilities.

Section 6.4 Process and Timing for Reciprocal Coordinated Flowgates.

The Parties shall comply with the process and timing for exchanging ATC/AFC calculations and Firm Flow calculations/allocations with respect to all RCFs as set forth in Attachment 1 and Attachment 2 to this Agreement.

Section 6.5 Real-Time Operations Process.

The Parties' real-time actions shall be governed by and in accordance with the Congestion Management Process.

Section 6.6 Costs Arising From Reciprocal Coordination of Flowgates.

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, the Party responsible for the flow that required the redispatch shall bear the costs of the redispatch.

Section 6.7 Reserve Sharing Events.

The MHEX interface is used for the delivery of Contingency Reserves between Manitoba Hydro and U.S. parties. This use of the MHEX interface shall be accommodated by the use of TRM under the Parties' respective Tariffs. MISO's and Minnkota's portion of the interface transfer capability will be reduced proportionately for TRM. The Parties' respective shares of TRM will not be affected by allocation sharing, because TRM is removed from each Party's interface transfer capability before allocation sharing occurs.

ARTICLE VII - COORDINATION OF OUTAGES

Section 7.1 Coordinating Outages.

The Parties will coordinate transmission and generation outages pursuant to the RC Agreement in effect between Minnkota and MISO.

ARTICLE VIII – RESERVED

ARTICLE IX - PLANNING COORDINATION

Section 9.1 Planning

The objective of the planning coordination process is to make certain that appropriate and adequate reviews of transmission planning functions are performed between the Parties on a collaborative basis to ensure comparability, efficiency and timeliness. MISO and Minnkota shall coordinate their planning processes by exchanging planning information required under this Agreement, and through joint cooperation between their respective Planning Authorities.

ARTICLE X – SCHEDULING PROTOCOLS

This Agreement is intended to provide clarity to the scheduling of energy as it relates to Minnkota generation, Minnkota load, the MISO Market and Off-System transactions in a manner consistent with the Settlement Agreements. The Parties agree to the terms and conditions as specified in this Article X.

Section 10.1 Scheduling Minnkota Resources to Load.

When Minnkota resources are using the Minnkota transmission system to serve Minnkota load, it is appropriate to use OMTA Schedules. When OMTA Schedules are used to document scheduling of Minnkota resources to serve Minnkota load, they will be capped at the OMTA Load Cap, which is established by Minnkota and confirmed by Otter Tail Power in accordance with the procedure documented in Section 4.1.6.

In order to track Minnkota's participation in the MISO Market, Minnkota will submit day-ahead schedules in the form of tags for the amount of Minnkota resources being used to serve Minnkota load. These tags will represent Minnkota resources within the MISO Balancing Authority Area being dispatched to serve Minnkota load within the MISO Balancing Authority Area, Minnkota resources external to the MISO Balancing Authority Area being dispatched to serve Minnkota load within the MISO Balancing Authority Area, and Minnkota resources within the MISO Balancing Authority Area being dispatched to serve Minnkota load external to the MISO Balancing Authority Area. Minnkota resources external to the MISO Balancing Authority Area may include (but are not limited to) hydro allocations that Minnkota receives from WAPA. Minnkota loads external to the MISO Balancing Authority Area may include (but are not limited to) Minnkota loads located within the WAPA Balancing Authority Area.

Minnkota may modify in real-time its day-ahead OMTA Schedules in accordance with MISO Market timing rules by submitting revised tags that reflect adjustments to the day-ahead OMTA Schedules.

Section 10.2 <u>Scheduling Off-System Transactions.</u>

The Parties agree that Minnkota has direct transmission connections with the Manitoba Hydro and WAPA transmission systems. Minnkota may establish direct connections with other transmission systems in the future. To the extent that Minnkota is engaging in purchase or sale transactions with such directly connected parties, Minnkota is using the Minnkota transmission system for the transactions, and it is appropriate to use OMTA Schedules. The OMTA Load Cap will apply if the schedule involves a purchase to serve Minnkota load, but it will not apply if the schedule is for an Off-System sale. A Minnkota schedule that is used to serve Minnkota load within the WAPA Balancing Authority Area is not an Off-System sale.

When Minnkota is engaging in Off-System transactions with a neighboring system that directly connects to the Minnkota transmission system, OMTA Schedules shall be used for those transactions to the extent that they are either sourced from Minnkota resources or sunk to Minnkota load.

When Minnkota is engaging in Off-System transactions involving a transmission system that does not directly connect to the Minnkota transmission system, but for which Minnkota has made arrangements for a transmission path to that system, OMTA Schedules shall be used for those transactions to the extent that the transactions are either sourced from Minnkota resources or sunk to Minnkota load.

When Minnkota is engaging in Off-System transactions involving a transmission system that does not directly connect to the Minnkota transmission system, and Minnkota does not arrange for transmission service through Manitoba Hydro, WAPA or another party with which Minnkota has a direct transmission connection, then Minnkota shall reserve MISO transmission service in advance of the transaction and have a tag in place before real-time. These transactions are not eligible to use OMTA Schedules.

If MISO transmission service is needed but has not been arranged in advance these schedules will be viewed as inappropriate use of MISO transmission service, and once the transaction is in real-time, MISO will have the right to interrupt/terminate the tag.

Section 10.3 Scheduling Minnkota-to-Market Transactions.

MISO agrees that to the extent that Minnkota is buying from the MISO Market to serve Minnkota load or selling into the MISO Market from Minnkota resources on an hourly basis, MISO transmission service is not needed. These transactions are not eligible to use OMTA Schedules and therefore the OMTA Load Cap will not apply.

Minnkota is encouraged, but is not required, to submit day ahead tags when engaging in MISO Market transactions as described in this section. Similarly, if Minnkota anticipates a transaction with the MISO Market in real-time that was not anticipated in the day-ahead time frame, Minnkota is encouraged but not required to submit modified tags according to MISO Market timing rules.

Minnkota transactions with the MISO Market in day ahead or real-time will be allowed to flow whether or not a tag has been submitted.

Section 10.4 <u>Scheduling Pass-Through Transactions.</u>

Minnkota will arrange MISO transmission service and submit non-OMTA Schedules in the form of tags for purchases from the MISO Market to support Off-System sales, or for Off-System purchases to support sales to the MISO Market.

(a) In order for an Off-System sale to be viewed as sourcing from the MISO Market, the Off-System sale must be occurring at the same time as the purchase from the MISO Market. A Minnkota schedule that is used to serve Minnkota load within the WAPA Balancing Authority Area is not a pass-through transaction.

(b) In order for an Off-System purchase to be viewed as sinking in the MISO Market, the Off-System purchase must be occurring at the same time as the sale to the MISO Market. A Minnkota schedule that is used to receive hydro allocations from WAPA as a preference customer is not a pass-through transaction.

To be viewed as a pass-through transaction, the transaction with the MISO Market does not need to match the magnitude and duration of the Off-System transaction. For example, an Off-System transaction for 100 MW for 12 hours does not need to be offset by a MISO transaction for 100 MW for the same 12 hours in order to be considered a pass-through transaction. If a MISO transaction occurs in any one or more of the 12 hours that is less than, equal to, or greater than the Off-System transaction, it will be viewed as supporting the Off-System transaction during the time period that both transactions are occurring. The portion of the Off-System transaction that is supported by the MISO transaction shall be considered a pass-through transaction in the amount of the lesser of the two transactions as determined on an hourly basis.

Conditions may change from the time the day-ahead OMTA Schedules are submitted and before the schedule start time such that initially when the day-ahead tags were submitted, Minnkota did not anticipate a transaction with the MISO Market to support the Off-System transaction but after the day-ahead tags were submitted, Minnkota now anticipates a transaction with the MISO Market. As long as Minnkota arranges MISO transmission service in advance and submits modified tags according to MISO Market timing rules, these will be considered an appropriate use of MISO transmission service.

If MISO finds that Minnkota is having a pass-through transaction with the MISO Market and no MISO transmission service was arranged in advance, this will be viewed as an inappropriate use of MISO transmission service, and once the transaction is in real time, MISO will have the right to interrupt/terminate the tag.

Section 10.5 <u>Directly Connected Third Parties Scheduling Transactions Through the Minnkota System.</u>

The Parties agree that Minnkota has direct transmission connections with certain neighboring transmission systems, as described in Section 10.2. To the extent that directly connected third parties, such as Manitoba Hydro or WAPA, are engaging in purchase or sale transactions with each other through the Minnkota system, they are using the Minnkota transmission system for the transactions. For these transactions, Minnkota transmission service will be required, but MISO transmission service will not be required.

Section 10.6 Maintaining Contract Path Capacity During Transmission Outages.

There can be a situation (based on the transmission configuration of the Parties) where the outage of one or more transmission facilities (either a planned outage or a forced outage) could result in one Party's load and/or generation being served radially from transmission facilities of the other Party. Likewise, there can be a situation (based on the transmission configuration of the Parties) where the outage of one or more transmission facilities (either a planned outage or a forced outage) could result in reducing or eliminating contract path capacity between the Party experiencing the outage and another entity where the other Party also has contract path capacity with this entity.

Where both MISO and Minnkota have transmission connections back to the same load and/or generation or the same other entity, a planned or forced outage experienced by one Party will not be considered to have diminished the contract path capacity to that load and/or generation or other entity (i.e. the contract path is as if no outage has occurred) provided the other Party has sufficient unused contract path capacity remaining that is equal to or greater than the amount of contract path capacity that is lost due to the outage. Where the other Party does not have sufficient unused contract path capacity remaining that is equal to or greater than the amount of contract path capacity that is lost due to the outage, the full amount of unused contract path capacity will be made available to the Party experiencing the outage provided that the other Party does not have an existing commitment on that unused contract path capacity for the expected duration of the outage.

For example, if MISO and Minnkota each have a single line to Substation A where both have load and/or generation, when the MISO line is out of service, MISO can rely on unused capacity on the Minnkota line to continue to serve its load and/or generation at Substation A. Likewise, when the Minnkota line is out of service, Minnkota can rely on unused capacity on the MISO line to continue to serve its load and/or generation at Substation A. Tie lines are treated in a similar manner. For example, if MISO and Minnkota each have a single line to Entity B where both have transactions with that entity, MISO can rely on unused contract path capacity on the Minnkota line to continue its transactions with Entity B when the MISO line is out of service. Likewise, Minnkota can rely on unused contract path capacity on the MISO line to continue its transactions with Entity B when the Minnkota line is out of service.

As used in this Section 10.6 the term "entity" means either a non-MISO Balancing Authority Area or a Local Balancing Authority within the MISO Balancing Authority Area. As used in this Section 10.6 "outage" and "out of service" do not refer to transmission facilities that are normally operated open.

This provides a mutual benefit to both Parties by allowing for the joint use of contract path capacity during planned and forced outages.

ARTICLE XI - (Reserved)

ARTICLE XII - ADDITIONAL COORDINATION PROVISIONS

Section 12.1 Application of Congestion Management Process.

To manage congestion in the Parties' integrated transmission systems, MISO will use the same congestion management redispatch procedures (including Security Constrained Economic Dispatch) to protect Minnkota's transmission facilities as it uses to protect the MISO Transmission System. The Parties expect that the systems and the operating protocols in the NERC standards and the Congestion Management Process applicable to their respective transmission systems may change and revisions of this Agreement may be required from time to time. Such revisions shall be subject to the provisions of Section 18.11.

Section 12.2 Security Constrained Economic Dispatch.

Minnkota will continue to offer its resources into the MISO Market and be economically dispatched through Security Constrained Economic Dispatch under the same rules as resources connected to MISO's Transmission System.

Section 12.3 Module E.

Module E-1 of the MISO Tariff provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone (LRZ) Peak Demand requirements on the Transmission System.

MISO will establish Planning Reserve Margin Requirements (PRMR) for Minnkota's Load within the applicable LRZ as described by Module E-1. Minnkota will meet its PRMR by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling Zonal Resource Credits (ZRC); (iii) purchasing ZRCs through the Planning Resource Auction (PRA) process; and/or (iv) paying the Capacity Deficiency Charge. Minnkota's data submittal requirements for Module E-1 are documented in Section 4.1.7.

MISO will enforce the Local Clearing Requirements (LCR), Capacity Import Limits and Capacity Export Limits for each LRZ in the PRA. An Auction Clearing Price (ACP) will be determined through the PRA process for each LRZ and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Minnkota, acting as a Market Participant that owns Planning Resources used to create ZRCs which clear in the PRA (or are identified in a submitted Fixed Resource Adequacy Plan), must meet the applicable performance requirements as described in sections 69A.3.9 and 69A.5 of Module E-1.

For further details regarding MISO's Resource Adequacy Processes please refer to Module E-1 of the MISO Tariff and the Resource Adequacy BPM. Module E-1 is subject to change.

Section 12.3.1 through Section 12.3.7 document the way that Module E coordination will occur under specific scenarios.

Section 12.3.1 [Self-Supply] Using Planning Resources Connected to Minnkota Transmission to Serve Load Connected to Minnkota Transmission

Planning Resources that are connected to the Minnkota transmission system may be called upon to meet Minnkota's PRMR. Minnkota is able to do so if it can demonstrate deliverability of such resources to its native load. Deliverability may be demonstrated through evidence of:

(a) Network Resource Interconnection Service under MISO Attachment X

OR

(b) Firm Minnkota transmission service that allows it to deliver this capacity from the Minnkota resources to Minnkota Load.

Section 12.3.2 [IMPORT] Bilaterally Importing Planning Resources Not Connected to Minnkota Transmission and Internal to the MISO Balancing Authority Area or Procuring through PRA

Planning Resources that are not connected to the Minnkota transmission system may be called upon to meet Minnkota's PRMR. This may come in the form of either procurement through the PRA or bilateral transactions. Minnkota is able to do so if it can demonstrate deliverability of such resources to its native load through evidence of Minnkota firm transmission service and MISO firm PTP transmission service to the border between MISO and Minnkota.

Section 12.3.3 [IMPORT External Resources] Importing Planning Resources Not Connected to Minnkota Transmission and that are External to the MISO Balancing Authority Area Using MISO Transmission

External Resources, including those specified in Diversity Contracts and PPAs, are eligible to be called upon to meet Minnkota's PRMR. When this occurs, Minnkota must demonstrate the External Resource qualifies as a Capacity Resource. This includes, demonstrating deliverability of such resources to Minnkota load through evidence of Minnkota firm transmission service and MISO firm transmission service to the border of Minnkota.

Section 12.3.4 <u>[IMPORT External Resources] Importing Planning Resources Not Connected to Minnkota Transmission and that are External to the MISO Balancing Authority Area Not Using MISO Transmission</u>

External Resources, including those specified in Diversity Contracts and PPAs, are eligible to be called upon to meet Minnkota's PRMR. When this occurs, Minnkota must demonstrate the External Resource qualifies as a Capacity Resource. This includes demonstrating deliverability of such resources to Minnkota load through evidence of Minnkota firm transmission service and external firm transmission service to the border of Minnkota.

Section 12.3.5 <u>[EXPORT] Exporting Planning Resources Connected to Minnkota Transmission into the MISO Balancing Authority Area through Bilateral Transactions or Offering into the PRA</u>

To the extent generation connected to the Minnkota transmission system wishes to export Zonal Resource Credits into the MISO Balancing Authority Area through bilateral transactions or offering into the PRA, it must demonstrate deliverability. Deliverability may be demonstrated through:

(a) Firm Minnkota transmission service that allows it to deliver this capacity to the MISO border

AND

(b) Firm transmission service on the MISO Transmission System from the border to the Load

OR

Network Resource Interconnection Service under MISO Attachment X.

To the extent generation connected to MISO transmission that is dependent on the Minnkota transmission system for connectivity to the rest of MISO wishes to export Zonal Resource Credits into the MISO Balancing Authority Area through bilateral transactions or offering into the PRA, it must demonstrate deliverability. Deliverability may be demonstrated through:

(a) Firm Minnkota transmission service that allows it to deliver this capacity to the MISO border

AND

(b) Firm transmission service on the MISO Transmission System from the border to the Load

OR

Network Resource Interconnection Service under MISO Attachment X.

Section 12.3.6 [EXPORT] Exporting Resource Connected to Minnkota Transmission to Outside of the MISO Balancing Authority Area Using MISO Transmission

Minnkota may export capacity from resources connected to the Minnkota transmission system to Balancing Authority Areas other than MISO using the MISO Transmission System but must demonstrate MISO firm transmission service.

Section 12.3.7 [EXPORT] Exporting Resource Connected to Minnkota Transmission to Outside of the MISO Balancing Authority Area Not Using MISO Transmission

Minnkota may export capacity from resources connected to the Minnkota transmission system to Balancing Authority Areas other than MISO not using the MISO Transmission System but must demonstrate a contractual obligation that prevents these units from participating in the MISO capacity market.

ARTICLE XIII - RESERVED

ARTICLE XIV - COOPERATION AND DISPUTE RESOLUTION PROCEDURES

Section 14.1 Administration of Agreement.

The Parties shall establish a Coordinating Committee to 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 XIV.

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

The Coordinating Committee 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.

Section 14.2 Dispute Resolution Procedures.

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.

Section 14.2.1 <u>Step One</u>.

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 Coordinating Committee 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 Coordinating 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 Coordinating Committee is unable to resolve within twenty (20) days of such Notice, either Party shall be entitled to invoke Step 2.

Section 14.2.2 <u>Step Two</u>.

A Party may invoke Step 2 by giving Notice thereof to the Coordinating Committee. In the event a Party invokes Step 2, the Coordinating Committee shall, in writing, and no later than five (5) days after the Notice, refer the dispute in writing to the Parties' Presidents (or equivalent officer if there is no President) 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 provide to 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 or to initiate a proceeding before a court of competent jurisdiction (in which case neither Party shall have the right to demand mediation).

Section 14.2.3 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 or may initiate a proceeding before a court of competent jurisdiction.

Section 14.2.4 Exceptions.

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.

ARTICLE XV - APPLICABLE CHARGES

Minnkota is a Market Participant under the MISO Tariff, and has registered its loads and resources in the MISO Market. This Agreement is intended to provide clarity to the operation of the Minnkota transmission system, its load and its generation resources consistent with the Settlement Agreements.

In order to coordinate the use of their respective transmission systems, and to clarify how certain transactions not contemplated by the Settlement Agreements should be settled under their respective tariffs, the Parties agree to the terms and conditions as defined in this Article XV. The summary table below provides an overview of market charges, and indicates the section of this Agreement where relevant scheduling protocols and market charges are documented in detail.

SUMMARY TABLE OF APPLICABLE CHARGES

	Where the Topic Is Covered In This Agreement		Applicability of MISO Charges				
	Scheduling Protocols	**Applicable Charges**	**Transm Service Charge**	**MVP**	**Reimbursed for Congestion & Losses**	**Market Charges**	**Admin**
MPC Gen to MPC Load	Sec. 10.1	Sec. 15.3.1	no	no	yes	no	yes
Off-System to MPC Load	Sec. 10.2	Sec. 15.3.2	no	no	yes	no	yes
MPC Gen to Off-System	Sec. 10.2	Sec. 15.3.3	no	no	yes	no	yes
MPC Gen to MISO Market	Sec. 10.3	Sec. 15.3.4	no	no	no	yes	yes
MISO Market to MPC Load	Sec. 10.3	Sec. 15.3.5	no	yes	no	yes	yes
MISO Market to Off-System	Sec. 10.4	Sec. 15.3.6	yes	yes	no	yes	yes
Off-System to MISO Market	Sec. 10.4	Sec. 15.3.7	yes	no	no	yes	yes
Off-System to Off-System Not Through MISO Transmission	Sec. 10.5	Sec. 15.3.8	no	yes	no	yes	yes

This table is for the purpose of convenience in summarizing the provisions of the Agreement. Refer to the individual sections for the actual provisions. In the event of a conflict between the terms of this table and the terms of a referenced section, the terms of the referenced section shall prevail.

Section 15.1 CPNODE Definition and Pseudo-Ties

Minnkota resources and Minnkota loads within the MISO Balancing Authority Area will be identified on a CPNode basis.

(a) If Minnkota generation and/or load has been pseudo-tied out of the MISO Balancing Authority Area where Minnkota has direct connections to the receiving Balancing Authority Area or has made contractual arrangements for the full pseudo-tie amount, it will be treated the same as any other resources or load physically located outside the MISO Balancing Authority Area for scheduling purposes.

(b) If generation and/or load physically located outside the MISO Balancing Authority Area has been pseudo-tied into the Minnkota area within the MISO Balancing Authority Area where Minnkota has direct connections to the sending Balancing Authority Area or has made contractual arrangements for the full pseudo-tie amount, it will be treated the same as any other Minnkota generation or load physically located inside the MISO Balancing Authority Area for scheduling purposes.

Section 15.2 Applicable Rates, Terms, and Conditions of MISO Tariff

MISO will impose MISO Administrative Fees, Transmission Service Charges, MVP charges under Schedule 26A, Market Charges, and congestion and loss charges in the manner described in this Article XV.

The MISO Tariff charges applicable to certain Minnkota transactions during the term of this Agreement shall be at the rates and on the terms and conditions set forth in the then current MISO Tariff, except as expressly set forth in this Agreement. For further clarity, the Parties have identified certain transactions which will be invoiced at the MISO Tariff rate, but only to the extent and upon such terms as set forth in this Article XV. All other Minnkota transactions in the MISO Market not specifically identified and addressed by this Agreement will be subject to the rates, terms and conditions of the MISO Tariff as the rates, terms and conditions of the Tariff may be amended from time to time by Commission order to the extent that Minnkota engages in such transactions. MISO shall not impose charges on Minnkota for new service(s) except to the extent that Minnkota utilizes or takes such service(s).

Section 15.3 Applicability of MISO Charges

Section 15.3.1 <u>Minnkota Resources Serving Minnkota Load</u>

To the extent that Minnkota is using its resources to serve its load, the following will apply:

(a) Minnkota will not be assessed a MISO Transmission Service Charge for service to its load;

(b) Minnkota will not be assessed a MISO MVP charge through Schedule 26A for service to its load;

(c) Minnkota will be reimbursed for congestion and losses included in the LMPs for service to its load;

(d) Minnkota will not be assessed MISO Market Charges for service to its load; and

(e) Minnkota will be assessed MISO Administrative Fees for service to its load.

Section 15.3.2 <u>Off-System Purchases to Serve Minnkota Load</u>

To the extent that Minnkota is engaging in Off-System purchases to serve Minnkota load, and a non-MISO transmission path exists or has been arranged as described in Section 10.2, the following will apply:

(a) Minnkota will not be assessed a MISO Transmission Service Charge for its Off-System purchases;

(b) Minnkota will not be assessed a MISO MVP charge through Schedule 26A for its Off-System purchases;

(c) Minnkota will be reimbursed for congestion and losses included in the LMPs for its Off-System purchases;

(d) Minnkota will not be assessed MISO Market Charges for its Off-System purchases; and

(e) Minnkota will be assessed MISO Administrative Fees for its Off-System purchases.

Section 15.3.3 Minnkota Resources Serving Off-System Sales

To the extent that Minnkota is utilizing its resources to engage in Off-System sales, and a non-MISO transmission path exists or has been arranged as described in Section 10.2, the following will apply:

(a) Minnkota will not be assessed a MISO Transmission Service Charge for its Off-System sales;

(b) Minnkota will not be assessed a MISO MVP charge through Schedule 26A for its Off-System sales;

(c) Minnkota will be reimbursed for congestion and losses for its Off-System sales;

(d) Minnkota will not be assessed MISO Market Charges for its Off-System sales; and

(e) Minnkota will be assessed MISO Administrative Fees for its Off-System sales.

Section 15.3.4 Minnkota Resources Selling into the MISO Market

To the extent that Minnkota is utilizing its resources for sales into the MISO Market on an hourly basis, the following will apply:

(a) Minnkota will not be assessed a MISO Transmission Service Charge for its sales into the MISO Market;

(b) Minnkota will not be assessed a MISO MVP charge through Schedule 26A for its sales into the MISO Market;

(c) Minnkota will not be reimbursed for congestion and losses for its sales into the MISO Market;

(d) Minnkota will be assessed MISO Market Charges for its sales into the MISO Market; and

(e) Minnkota will be assessed MISO Administrative Fees for its sales into the MISO Market.

When Minnkota's sales into the MISO Market do not coincide with Minnkota Off-System purchases as described in Section 10.4 , its sales into the MISO Market will be viewed as sourcing from Minnkota resources within the MISO Balancing Authority Area. The generation amount above the Minnkota metered load is a sale to the MISO Market that will be settled as any other Market Participant delivering into the MISO Market except that no MISO Transmission Service Charge shall be imposed.

Section 15.3.5 Minnkota Purchasing from the MISO Market to Serve Minnkota Load

To the extent that Minnkota is purchasing from the MISO Market to serve its load on an hourly basis, the following will apply:

(a) Minnkota will not be assessed a MISO Transmission Service Charge for withdrawals from the MISO Market;

(b) Minnkota will be assessed a MISO MVP charge through Schedule 26A for withdrawals from the MISO Market;

(c) Minnkota will not be reimbursed for congestion and losses for withdrawals from the MISO Market;

(d) Minnkota will be assessed MISO Market Charges for withdrawals from the MISO Market; and

(e) Minnkota will be assessed MISO Administrative Fees for withdrawals from the MISO Market.

When Minnkota's withdrawals from the MISO Market do not coincide with Minnkota Off-System sales as described in Section 10.4, the withdrawals from the MISO Market will be viewed as sinking to Minnkota load within the MISO Balancing Authority Area. Withdrawals from the MISO Market are purchases that will be settled as any other Market Participant buying from the MISO Market, except that no MISO Transmission Service Charge shall be imposed.

Section 15.3.6 Minnkota Purchasing from the MISO Market While Simultaneously Engaging in Off-System Sales

To the extent that Minnkota is purchasing energy from the MISO Market to support Off-System sales as described in Section 10.4, the following will apply:

(a) Minnkota will be assessed a MISO Transmission Service Charge for withdrawals from the MISO Market to support Off-System sales;

(b) Minnkota will be assessed a MISO MVP charge through Schedule 26A for withdrawals from the MISO Market to support Off-System sales;

(c) Minnkota will not be reimbursed for congestion and losses for withdrawals from the MISO Market to support Off-System sales;

(d) Minnkota will be assessed MISO Market Charges for withdrawals from the MISO Market to support Off-System sales; and

(e) Minnkota will be assessed MISO Administrative Fees for withdrawals from the MISO Market to support Off-System sales.

Section 15.3.7 Minnkota Selling into the MISO Market While Simultaneously Engaging in Off-System Purchases

To the extent that Minnkota is selling into the MISO Market while simultaneously engaging in Off-System purchases as described in Section 10.4, the following will apply:

(a) Minnkota will be assessed a MISO Transmission Service Charge for the amount of Off-System purchases sold into the MISO Market;

(b) Minnkota will not be assessed a MISO MVP charge through Schedule 26A for the amount of Off-System purchases sold into the MISO Market;

(c) Minnkota will not be reimbursed for congestion and losses for the amount of Off-System purchases sold into the MISO Market;

(d) Minnkota will be assessed MISO Market Charges for the amount of Off-System purchases sold into the MISO Market; and

(e) Minnkota will be assessed MISO Administrative Fees for the amount of Off-System purchases sold into the MISO Market.

Section 15.3.8 Third Party Transactions Through the Minnkota System

To the extent that third parties that are directly connected to the Minnkota transmission system are engaging in transactions through the Minnkota system, and a non-MISO transmission path exists or has been arranged as described in Section 10.5, the third party customer will need to tag and schedule the flows through the MISO Balancing Authority, and the following will apply to the transactions:

(a) The third parties will not be assessed a MISO Transmission Service Charge;

(b) The third parties will be assessed a MISO MVP charge through Schedule 26A;

(c) The third parties will not be reimbursed for congestion and losses included in the LMPs;

(d) The third parties will be assessed MISO Market Charges; and

(e) The third parties will be assessed MISO Administrative Fees.

Minnkota will not be assessed any charges by MISO in association with a third party transaction as described in this Section. Minnkota transmission service charges will be applied to the third party transaction in accordance with the Minnkota OATT.

ARTICLE XVI - ACCOUNTING AND ALLOCATION OF COSTS OF JOINT OPERATIONS

Section 16.1 Revenue Distribution.

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

Section 16.2 Billing and Invoicing Procedures.

Each Party shall render invoices to the other Party for any amounts that may be due under this Agreement in accordance with its customary billing practices and payment shall be due in accordance with the invoicing Party's customary payment requirements. 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). To the extent that any payment is due by Minnkota for any service obtained pursuant to the MISO Tariff, including but not limited to transmission service, energy, operating reserves or Reliability Coordination Service, invoices shall be presented by MISO and paid by Minnkota as set forth in the MISO Tariff.

Section 16.3 Access to Information by the Parties.

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 reasonably 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 upon reasonable advance written notice. Each Party shall bear its own costs associated with any such audits.

ARTICLE XVII - RETAINED RIGHTS OF PARTIES

Section 17.1 Parties Entitled to Act Separately.

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. Neither Party is a subcontractor to the other. 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.

ARTICLE XVIII - ADDITIONAL PROVISIONS

Section 18.1 Confidentiality.

Section 18.1.1 Meaning.

The term "Confidential Information" shall mean information and documents provided by one Party to the other Party hereunder, whether furnished before or after the Effective Date, whether oral, written or recorded/electronic, and regardless of the manner in which such information and documents are furnished, that are marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary. "Confidential Information" also includes: (a) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any such confidential or proprietary information or documents; (b) 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 Part 358 or a Party's Standards of Conduct that may be on file with the FERC; and (c) data provided pursuant to Section 4.

Section 18.1.2 Protection.

During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information of the other Party. Except as set forth herein, each Party shall keep in confidence, and not copy, disclose, or distribute, any Confidential Information or any part thereof, without the prior written permission of the issuing Party. A Party receiving 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. 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 18.1 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; or (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 commercially reasonable efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information. Notwithstanding the foregoing confidentiality obligation, solely with respect to Confidential Information provided by one Party to the other Party pursuant to Section 4, a Party is authorized to release bid, pricing and other market data on an aggregated basis and transmission data, in accordance with such Party's tariff or other governing documents, but only after expiration of the time period controlling the producing Party's disclosure of such information, as such period is described in the producing Party's governing documents from time to time.

Section 18.2 Protection of Intellectual Property.

Section 18.2.1

All Intellectual Property and modifications to, and enhancements of, and derivatives of such Intellectual Property (i) owned by a Party on or before the Effective Date; or (ii) developed by a Party after the Effective Date, 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.

Section 18.2.2

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.

Section 18.3 Indemnity.

Section 18.3.1 <u>Indemnity of MISO</u>.

Minnkota 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 Minnkota or any of Minnkota'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 Minnkota 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 by Minnkota in violation of Section 18.2.; and

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

Section 18.3.2 <u>Indemnity of Minnkota.</u>

MISO will defend, indemnify and hold Minnkota harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against Minnkota, 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 Minnkota or any of Minnkota's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon Minnkota or Minnkota'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 by MISO 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 Minnkota.

Section 18.3.3 Damages Limitation.

Section 18.3.3.1

Except for amounts agreed to be paid under Article XVI by one Party to the other under this Agreement, or amounts due under the MISO Tariff, 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.

Section 18.3.3.2

Except for amounts agreed to be paid by one Party to the other under this Agreement, 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.

Section 18.4 Effective Date and Termination.

MISO shall file this Agreement with FERC on or before July 20, 2015 and each Party shall cooperate with each other as necessary and appropriate to facilitate such filing and acceptance or approval by FERC. MISO shall request from FERC an effective date of September 1, 2015. The term of this Agreement commences upon the effective date stated in the acceptance or approval by FERC (the "Effective Date"). Subject to the provisions of Section 18.12 (Regulatory Changes) and Section 18.13 (Severability), the initial term of this Agreement shall be five (5) years from the Effective Date, and shall automatically renew thereafter for successive one (1) year terms unless at least six (6) months' Notice of termination is provided in writing prior to the end of the initial term or any successive term thereafter. Notwithstanding such initial and successive terms, if Minnkota commits to joining an RTO other than MISO as a transmission owner, the Parties shall in good faith negotiate to amend this Agreement to accommodate such RTO membership while preserving the mutual benefits of this Agreement to each Party. If the Parties are unable to agree upon such an amendment after six (6) months' good faith negotiations (or such longer period as the Parties may in writing agree upon), then this Agreement shall terminate effective on the date that Minnkota's transmission facilities are integrated into such RTO. If Minnkota commits to join MISO as a transmission owner, this Agreement will terminate on the effective date of Minnkota's integration into MISO. Upon one Party providing Notice of termination to the other Party, MISO shall timely file a notice of termination with FERC to effectuate such termination in accordance with the Notice provision in this Section 18.4, provided that such filing shall not prejudice the right of either Party to object to or challenge such termination. The Agreement shall terminate and cease to be effective upon FERC acceptance of such filing of the notice of termination (in accordance with the effective date provided for in such acceptance) or pursuant to 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.

Section 18.5 Survival Provisions.

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 (Amendment) and Section 18.14 (Execution of Counterparts)

Section 18.6 No Third-Party Beneficiaries.

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).

Section 18.7 Successors and 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; or (b) in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets, or (c) Minnkota may assign this Agreement to the Rural Utilities Service without consent of MISO, but shall provide MISO with prompt written notice upon any such assignment. 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.

Section 18.8 Force Majeure.

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.

Section 18.9 Governing Law.

This Agreement shall be interpreted, construed and governed by the applicable federal law, and to the extent not governed by federal law, the laws of the state of Delaware without giving effect to its conflict of law principles.

Section 18.10 Notice.

Whether expressly so stated or not, all legal notices, demands, requests and other communications (other than reliability and operational 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:

Minnkota Power Cooperative, Inc.
5301 32nd Ave S
Grand Forks, ND 58201
Attention: Vice President, Planning and Operations

Midcontinent Independent System Operator, Inc.
701 City Center Drive
Carmel, Indiana 46032
Attention: General Counsel

Section 18.11 Amendment.

Except as may otherwise be provided in this Section 18.11, 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. It is the intent of the Parties that, only during the initial term of this Agreement and to the maximum extent permitted by law, this Agreement, and the rates, terms and conditions hereof, shall not be subject to change under Sections 205 and 206 of the Federal Power Act absent the written agreement of the Parties, and that the standard of review for changes unilaterally proposed by a Party or FERC, acting *sua sponte* or at the request of a third party, shall be the public interest application of the just and reasonable standard of review as set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 554 U.S. 527 (2008), and *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 130 S.Ct. 693 (2010) (the "*Mobile-Sierra*" public interest standard of review). In the event that the Commission declines to impose the *Mobile-Sierra* public interest application of the just and reasonable standard of review for changes unilaterally proposed by FERC or a third party, unless the Parties otherwise mutually agree neither Party shall encourage or support any such unilaterally proposed change. During any subsequent term after the initial term of this Agreement, nothing in this Section 18.11 shall be construed to impair the right of either Party, or any third party, to file unilaterally with FERC pursuant to Section 205 or Section 206 of the Federal Power Act, or of FERC acting on its own motion, to make any change in this Agreement, or to seek any relief or to exercise any right a Party may have under the Federal Power Act or this Agreement, applying the just and reasonable standard of review. Prior to a Party unilaterally filing with FERC a change to this Agreement, or the rates, terms or conditions hereof, such Party shall provide to the other Party the proposed change in writing at least sixty (60) days prior to filing such change with FERC, and shall thereafter negotiate in good faith with the other Party to mutually agree upon such change (as proposed by such Party or as otherwise may be agreed upon by the Parties); such negotiations shall include, at the request of a Party, at least one in-person meeting of the Parties.

Section 18.12 Regulatory Changes.

If any regulatory or other governmental authority requires a change in the terms of this Agreement in such authority's initial review and approval or acceptance of this Agreement (whether pursuant to a complaint, protest, comment, or other pleading by either Party or a third party or pursuant to such authority's own investigation or other process) that materially adversely affects a Party (as such Party may in its sole discretion determine), then such Party may upon written notice to the other Party terminate this Agreement. If, after initial approval or acceptance by applicable regulatory or other governmental authorities, a court or any regulatory or other governmental authority requires a change in the terms of this Agreement (whether pursuant to a complaint, protest, comment, or other pleading by either Party or a third party or pursuant to such court's or authority's own investigation or other process) that materially adversely affects a Party (as such Party may in its sole discretion determine), then such Party may upon written notice to the other Party terminate this Agreement.

Section 18.13 Severability.

Subject to Section 18.12, if a court or any regulatory authority with jurisdiction holds that any provision of this Agreement is invalid or unenforceable, or if, as a result of a change in any federal or state law or constitutional provision, or any rule or regulation promulgated pursuant thereto, any provision of this Agreement is rendered invalid or results in the impossibility of performance thereof, the remaining provisions of this Agreement not affected thereby shall continue in full force and effect. In such event, the Parties shall promptly enter into good faith negotiations regarding new provisions to restore this Agreement as nearly as possible to its original intent and effect. If the impact of such holding or promulgation materially affects a Party's rights, duties, or obligations contemplated under this Agreement (as such Party may in its sole discretion determine), then such Party may terminate this Agreement as provided in Section 18.12, upon written notice to the other Party.

Section 18.14 Execution of Counterparts.

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.

[Signatures appear on the following page]

The Parties have caused this Coordination and Operating Agreement to be executed by their duly authorized representatives.

MINNKOTA POWER COOPERATIVE, INC.

By: ______________________

Name: ROBERT MCLENNAN

Title: PRESIDENT/CEO

Date: 7/15/2015

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

By: ______________________

Name: JENNIFER CURRAN

Title: Vice President, System Planning + Seams Coordination

Date: 7/14/2015

Attachment 1

TFC / AFC

And

Transmission Service Request Evaluation

Coordination

Protocol

Original Version
January 15, 2009

Updated For
Minnkota/MISO Coordination Agreement
On July 1, 2015

Purpose

The calculation of TFC and AFC pertains to a forecast of transmission capacity that may be available for use by transmission customers. Use of transmission capacity under one tariff can impact the loadings, voltages and stability of electric transmission systems that must be coordinated with use of transmission capacity under a parallel tariff. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the TFC and AFC values for its own transmission system. The collection of data related to calculation of AFC is necessary to assure reliable coordination, and also to permit all tariff administrators to determine if, due to lack of transmission capacity, they must refuse a transmission reservation in order to avoid overloading of facilities.

Coordination of transmission service request evaluation practices between tariff administrators is necessary to ensure comparable, reliable and efficient evaluations. AFC is used, with respect to flowgates, to describe remaining capability on a flowgate.

Because Minnkota is embedded within the OTP LBA, it is difficult to distinguish between OTP generation-to-load impacts and Minnkota generation-to-load impacts. Likewise, Minnkota and OTP are co-owners in a generator and they have an interconnected transmission system that is used to serve their combined load. As such, MISO and Minnkota have agreed to have a combined market flow that MISO reports to the IDC for congestion management purposes and to have a combined historic Allocation that is used to set the Firm Flow Limit on MISO Market Flows as well as to process firm transmission service requests by MISO and Minnkota. This decision to have combined Market Flows and historic Allocations has resulted in other arrangements between MISO and Minnkota that affect AFC calculations and evaluation of transmission service requests:

- MISO will perform AFC calculations on Minnkota flowgates and these AFCs will be used when processing Minnkota transmission service requests.
- The MHEX Flowgate is unique in that MISO and Minnkota each have contractual ASTFC rights on the MHEX interface that will be separately maintained (not combined). MISO will calculate a combined MISO and Minnkota AFCs and separate MISO and Minnkota ASTFC values on the MHEX interface for both Parties and will track firm usage for both Parties.

Minnkota and MISO have agreed to the following method of implementation:

- Minnkota will maintain a separate OASIS page for content posting but will point to the MISO OASIS for TSR submittal, approval, AFC/ATC calculation and AFC/ATC postings.
- MISO will collaborate with Minnkota on the performance of flowgate identification studies and Transmission Reliability Margin (TRM) studies to determine flowgates and TRM on the Minnkota Transmission System in a manner consistent with Minnkota's ATC Implementation Document and TRM Implementation Document.
- MISO will provide AFC overrides for Minnkota flowgates to third parties for coordination purposes.

- MISO will calculate and post AFC/ASTFC values for Minnkota Flowgates and process Minnkota TSRs under the MISO OASIS. Minnkota TSRs will have a unique service type to distinguish them from MISO TSRs.
- MISO will administer short – term Minnkota TSRs.
- Minnkota will perform studies for long-term TSRs and coordinate the TSR approval with MISO.
- MISO will administer tagging of schedules that are entered for Minnkota TSRs when there is not a coordinated MISO TSR on the path. When a coordinated MISO TSR is already on the tagging path, the Minnkota TSR should not be listed on the tag.

Minnkota will, at any time in the future, have the option to provide its own fully functional OASIS for TSR submittal, TSR and tag approval, ATC calculation, and AFC/ATC postings. If Minnkota exercises this option to provide its own OASIS, MISO will provide AFC values and distribution factors so that the Minnkota OASIS can calculate ATC on its own paths.

Minnkota may use a contractor for administration of transmission service processes. In this protocol, it is recognized that references to Minnkota will apply to either Minnkota or its designated contractor. MISO shall coordinate with Minnkota or its contractor, as appropriate, in respect to TFC/AFC calculations and transmission service request evaluations.

1.1 Transmission Interchange Schedules/Net Scheduled Interchange

1.1.1 Purpose

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

1.1.2 Requirements

As an entity embedded within a MISO LBA, MISO already has access to Minnkota interchange schedules / net scheduled interchange, as required to permit accurate calculation of AFC values. Since MISO will be making the AFC calculation for Minnkota Flowgates, there is no need for MISO to provide its interchange schedules / net scheduled interchange to Minnkota.

1.2 Transmission Reservations

1.2.1 Purpose

Beyond the operating horizon, the impacts of existing transmission reservations 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* Open Access

Transmission Tariffs approved by the FERC allow firm service on a given path to be redirected 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 the portions of a source to sink reservation may not be able to be associated prior to scheduling, double-counting in the AFC determination process is a possibility. Reservations on either the Minnkota or MISO tariffs will be incorporated into transmission models developed by Minnkota and MISO as outlined in this document to improve coordination.

1.2.2 Requirements:

a) Minnkota's actual transmission reservation information will reside on the MISO OASIS node and will be used by MISO as outlined in this document for integration into MISO's AFC determination process and for integration into MISO's day-ahead and real-time energy market processes.

b) MISO will model Minnkota's Sources, Sinks, Flowgates (including RCFs), in the MISO OASIS and the MISO AFC process. PORs, PODs and ATC paths will be modeled/defined as per MISO AFC process.

c) MISO shall use Minnkota's reservation data including both firm and non-firm reservations in its day-ahead and real-time energy market. MISO's market shall include the effects of Minnkota's firm and non-firm reservations in the calculation of parallel path impacts from Minnkota on the MISO system.

d) In general, Minnkota and MISO shall require a transmission reservation for all service sourcing in their own footprint and sinking outside their own footprint. Examples of exceptions include certain grandfathered agreements, certain MISO market carve-outs and certain generation reserve sharing obligations and other circumstances which would all be addressed on a case-by-case basis consistent with the applicable Party's business practices.

e) In general, Minnkota and MISO shall require a transmission reservation for service sourcing outside their own footprint and sinking inside their own footprint. Examples of exceptions include certain grandfathered agreements, certain MISO market carve-outs and certain generation reserve sharing obligations and other circumstances which would all be addressed on a case-by-case basis consistent with the applicable Party's business practices.

f) MISO has agreed to compute AFCs on both MISO and Minnkota Flowgates using business practices MISO has adopted in its AFC calculation process. With respect to importing reservations from other OASIS nodes, Minnkota and MISO agree to the following principles regarding the filtering of such reservations to prevent double-counting reservations and to prevent decrementing for certain partial-path reservations:

MISO Reservation Filtering Rules:

i. MISO shall include active transmission service requests on its own OASIS node (e.g., those requests that have a status of STUDY, ACCEPTED, COUNTEROFFER, REBID and CONFIRMED).

ii. MISO shall not be required to include active transmission service requests from non-MISO OASIS nodes, except that MISO will include reservations from the Minnkota OASIS node (e.g., those Minnkota requests that have a status of STUDY, ACCEPTED, COUNTEROFFER, REBID and CONFIRMED).

iii. If MISO can determine that the transmission service sold by another Transmission Provider other than Minnkota will require transmission service on the MISO tariff (the request is partial path), MISO will not include the STUDY, ACCEPTED, COUNTEROFFER, REBID or CONFIRMED status reservation from the other Transmission Provider in its data set.

iv. For transmission service sold by Minnkota, MISO will include the STUDY, ACCEPTED, COUNTEROFFER, REBID and CONFIRMED status Minnkota reservations in its data set provided MISO is not on the path of the service sold (is not listed as the source/sink or the POR/POD). If MISO is on the path, the Minnkota reservation will be discarded assuming a duplicate reservation exists in the MISO set.

v. For transmission service between two Transmission Providers where MISO is importing reservations from both Transmission Providers, MISO shall keep the source reservation and discard the sink reservation.

vi. For transmission service between two Transmission Providers where MISO is only importing reservations from one of the Transmission Providers, MISO shall keep the reservation if the Transmission Providers are either the source or the sink.

vii. If a Transmission Provider has sold a wheel (the source balancing authority area and sink balancing authority area are not connected to the Transmission Provider's Transmission System) and MISO is importing reservations from either the source balancing authority area or the sink balancing authority area, MISO shall discard the wheel reservation.

viii. If a Transmission Provider has sold a wheel and MISO is not importing reservations from either the source balancing authority area or the sink balancing authority area, MISO shall keep the wheel reservation.

g) To provide a balanced approach to AFC calculations which recognizes operating experience, MISO shall implement practices for modeling reservations, including external reservations, and netting practices for any allowance of counterflows created by confirmed reservations in electrically opposite directions as outlined in the MISO ATCID. The reservation importing rules described in this document are applied to this counterflow policy. At a minimum, Minnkota and MISO agree to these practices for Reciprocal Coordinated Flowgates ("RCFs") and may or may not implement these practices for flowgates that are not RCFs:

Minnkota and MISO reserve the right to modify the above netting and counterflow practices for firm and non-firm AFC postings following operational experience with such practices. Changes to the above practices shall be made after review of Minnkota and MISO considering stakeholder review and input.

1.3 AFC Components

1.3.1 Purpose

The development of AFC components includes several factors including:

- Total Flowgate Capability (or "TFC"),
- The base anticipated flow (referred to as Existing Transmission Commitments or "ETC", which for Minnkota and MISO are a combined "Base Flow") ,
- Transmission Reliability Margin (or "TRM"), and
- Capacity Benefit Margin (or "CBM").

Coordinated approaches for determining these factors with respect to RCFs are desirable to ensure consistent and comparable AFC components. At a minimum, Minnkota and MISO agree to the following practices for RCFs between Minnkota and MISO and may or may not implement these practices for flowgates that are not reciprocal between Minnkota and MISO.

1.3.2 Requirements:

a) With respect to TFC, Minnkota and MISO shall

i. Consider or request their respective Transmission Operators (as such term is defined in the NERC Standards) to consider neighboring system facility ratings and system limits (including stability) in the determination of TFC for flowgates in which the facilities are jointly owned (both MISO and Minnkota Transmission Operators (as such term is defined in the NERC Standards) have ownership in facilities used in the flowgate definition),

ii. Request their respective Transmission Operators (as such term is defined in the NERC Standards) to jointly determine the TFC for interdependent flowgates (such as MHEX) where the flowgate TFC is dependent on assumptions regarding flow levels on other flowgates and the flowgate protects both MISO and non-MISO systems, and

iii. Exchange the TFC components of their flowgates with the other Party and use them in their process

b) With respect to ETC or Base Flow,

i. MISO shall determine a combined Base Flow from the transmission usage corresponding to the combined MISO and Minnkota designated network resources being used to serve the native load on the MISO and Minnkota RCFs based on the assumption that the combined MISO and Minnkota impacts may cause flows up to their combined firm capacity allocation on any RCF. The impacts from MISO and Minnkota point to point reservations are not included in the combined Base Flow. If the projected combined Base Flow on a flowgate is less than MISO's and Minnkota's combined firm allocation, MISO and Minnkota shall use in the AFC calculations the combined Base Flow estimate, not the firm allocation.

c) Minnkota and MISO RCFs shall include the effects of certain of the study-status reservations in a commonly agreed upon and consistent manner.

i. Minnkota and MISO shall continue to utilize practices by which shorter term firm service will be made available if flowgate capacity is insufficient to accommodate shorter term service due to the inclusion of study-status reservations and/or conditional confirmed reservations and the System Impact Studies and/or facility improvements required for such requests will not be completed during the term of the short term service being offered.

d) To coordinate the impacts of roll-over rights, Minnkota and MISO shall:

i. Track reservations with roll-over rights. The requests to include in the tracking mechanism should include all Minnkota and MISO reservations as well as appropriate third party reservations. The roll-over right tracking mechanism shall include the ability to track the end-date of the roll-over right period for those requests in accordance with FERC Order No. 890 requirements (60 days prior to the end of the service for service in effect prior to Order No. 890 and one year prior to the end of the service for service in effect post Order No. 890 or following the first renewal post Order No. 890),

ii. Each 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 unless explicitly stated in the applicable service agreement.

iii. Both Parties shall limit approvals of requests for transmission service between the Parties, including roll-over transmission service, so as to not exceed the contract path limits in cases where contract path limits exist provided that firm transmission service customers retain the rollover rights and reservation priority granted to them under the applicable Party's OATT.

iv. Ensure that all Minnkota and MISO flowgate AFC postings include the effects of all confirmed reservations with roll-over rights from the rollover right tracking mechanism described above,

v. Exclude from the roll-over calculation any reservations which were granted on the condition of no roll-over rights, and

vi. Ensure the requests to be considered in the rollover right calculation pass the reservation importing rules described in this document.

1.4 Evaluation Practices

1.4.1 Purpose

Coordinated approaches in performing planning studies supporting AFC components and studies evaluating transmission service requests are desirable to ensure consistent and comparable AFC component development and transmission service evaluations.

1.4.2 Requirements:

a) Minnkota and MISO shall comparably evaluate the impacts of new network resource additions, new short term transmission service requests and new transmission system facilities.

b) Minnkota and MISO shall implement a comparable process with respect to on-the-path and off-the-path transmission service request evaluations. The goal of the process is to appropriately evaluate transmission service in instances where a partial path transmission service request may have already decremented flowgate AFC. The process will be initiated when a transmission customer identifies an instance where an off-the-path flowgate(s), may have been evaluated and decremented by another Transmission Provider. This will only occur when new service fails evaluation on an off-the-path flowgate where transmission use has been taken into account on the off-the-path flowgate(s). The process will be manual and apply only to monthly or yearly firm requests. The process shall not apply in situations where the customer has an approved partial path reservation if AFC values on an off-the-path flowgate are not considered in that entity's request evaluation process.

c) Both Parties may use discretion with respect to including counterflow impacts when evaluating long-term firm transmission reservations. Such discretion shall be documented in the system impact study developed in regard to such service.

d) With respect to re-directing transmission service, the on-the-path/off-the-path evaluation procedure noted above is recognized with the following additional provisions. A request to re-direct existing service will be treated as a new request. The following rules shall apply:

i. If the original request was accepted by Minnkota or MISO only because the request was partial path and the other Party (Minnkota or MISO) was on the original contract path or were the source/sink point for the original reservation:

a. For any re-direct of such original service on the Minnkota or MISO system in which the other Party is not on the re-directed contract path and is not the source/sink point for the re-directed reservation, the flowgates of the other Party will be considered in evaluation of the re-direct service.

b. For any re-direct of such original service on the Minnkota or MISO system in which the other Party is on the re-directed contract path or is the source/sink point for the re-directed reservation, the other Party's flowgates will not be considered in the evaluation of the re-directed service.

ii. If the original request was accepted by Minnkota or MISO for reasons other than the application of the on-the-path/off-the-path procedure (such reasons could include: (a) the request was accepted because there was adequate AFC on the flowgate when the request was evaluated, or (b) the request had less than the minimum acceptable impact on the flowgates to be evaluated (less than a 5% distribution factor on a PTDF flowgate or less than a 3% impact on an OTDF flowgate)):

a. For a re-direct of such original service in which the other Party is not on the re-directed contract path and is not the source/sink point for the re-directed reservation, the other Party's flowgates will be considered in the evaluation of the re-direct request.

   i. In such cases, if the distribution factor of the re-directed path on the flowgates is greater than the minimum acceptable distribution factor cutoff values and is less than or equal to the distribution factor of the original path on such flowgates, the service will be accepted.

   ii. If the distribution factor of the re-directed path on the flowgate is greater than the minimum acceptable distribution factor cutoff value and is greater than the distribution factor of the original path, the service will be refused if there is not adequate AFC available to provide the service or mitigation (flowgate re-dispatch or system expansion) is unavailable.

b. For any re-direct of such original service on the Minnkota or MISO tariffs in which the other Party is on the re-directed contract path or is the source/sink point for the re-directed reservation, the other Party's flowgates will not be considered in the evaluation of the re-direct request.

1.5 Calculated Firm and Non-firm Available Flowgate Capability

1.5.1 Definitions

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) and roll-over transmission service rights modeled.

1.5.2 Purpose

Data collection 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 tariff respects the other tariff's Flowgates as follows.

1.5.3 Requirements

(a) MISO will develop firm and non-firm AFC for both MISO and Minnkota Flowgates.

(b) Minnkota and MISO will accept or reject transmission service requests based upon projected loadings on these Flowgates as well as on RCFs. Minnkota and MISO firm transmission service request evaluation will honor firm AFC postings on all RCFs. Minnkota and MISO non-firm transmission service request evaluations will honor non-firm AFC postings on all RCFs.

ATTACHMENT 2

Congestion Management Process (CMP) MASTER

<u>Version 1.8</u>

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 2 shall have the same meaning set forth in the body, appendices, and attachments of the *Minnkota-MISO Coordination and Operation Agreement*.

- *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 (October 1, 2008)
Updated to reflect MISO becoming the Balancing Authority effective January 6, 2009. References of Control Areas were changed to Balancing Authority Area

Revision 1.3 (March 31, 2009)
Includes changes to the baseline CMP which were filed and approved by FERC between May 1, 2008 and February 19, 2009, along with changes agreed to by MISO and MAPPCOR under docket ER09-245-000. The changes include modifying the Market Flow Threshold to 5%; modifying the marginal zone processes (Section 5.2 *Quantify and Provide Data for Market Flow and Appendix B Determination of Marginal Zone Participation Factors*) to support the manner in which MISO uses marginal zones and submits marginal zone information to the IDC; and removing TLR Option from *Appendix E TLR Avoidance (or Reserved).*

Revision 1.4 (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 1.5 (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 (or Reserved)* and *Appendix G – Allocation Adjustments for New Transmission Facilities and/or Designated Network Resources*.

Revision 1.6 (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	Revised language to require a Market-Based Operating Entity to consistently

4.1.1	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 1.7 (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 3.2.5	Updated the number of Coordination Flowgate studies from four to five.
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 1.8 (June 2, 2022)

Updated to reflect the PFV changes as per NAESB Standard

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Section 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:

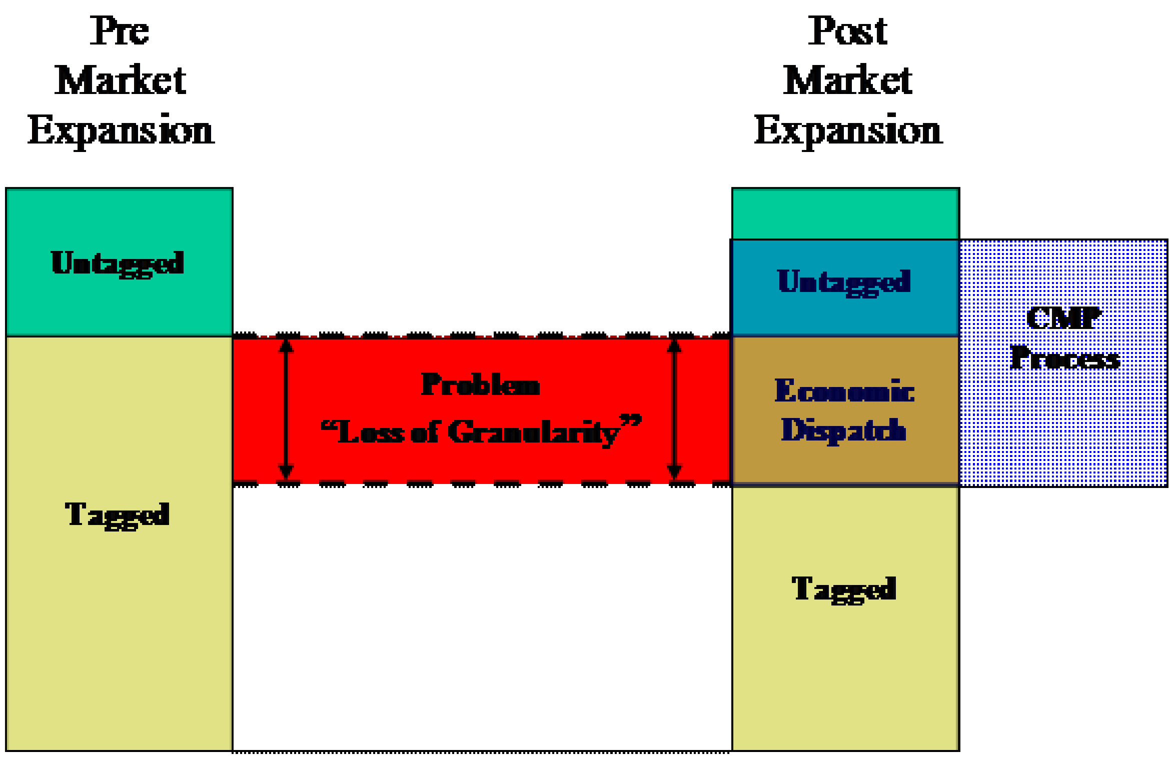
- Point-to-point schedules sinking in, sourcing from, or passing through an Operating Entity will be tagged.
- The IDC or a similar repository of schedules is needed at the Interconnection's current state and for the foreseeable future.

- 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).

Section 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.

Section 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.

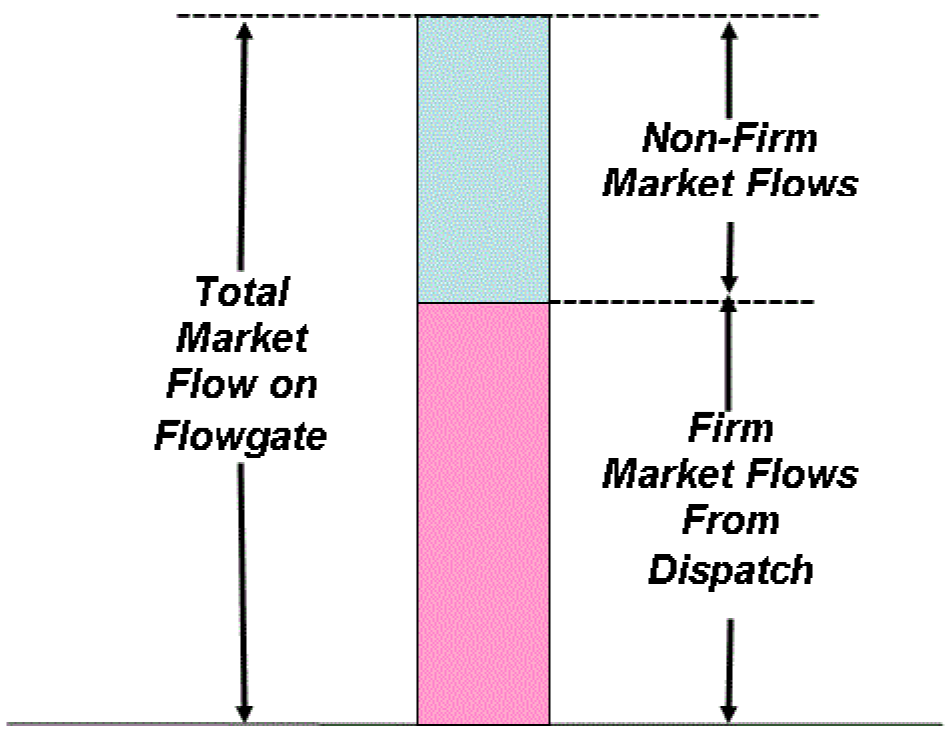
5. AFC Calculation and Posting AFCs:
    a. The managing entity will calculate and post AFCs for Tie Line Flowgates in accordance with the managing entity’s processes (i.e., the managing entity will treat the Flowgates as internal Flowgates).
    b. The managing entity will post AFC files for Tie Line 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.

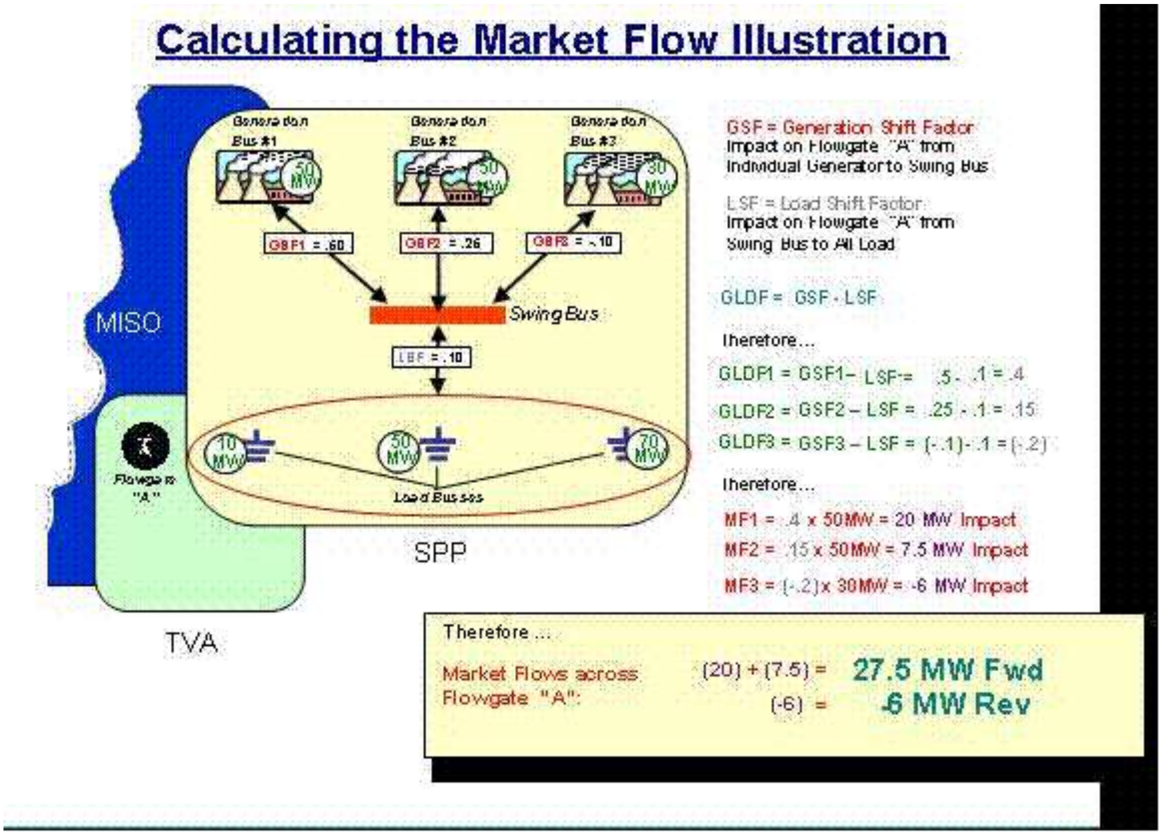
4.1 Market Flow Determination

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 (each of which report Market Flow to the IDC), 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.

Section 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 estimator 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 <u>and</u> 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 and 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.

Section 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.

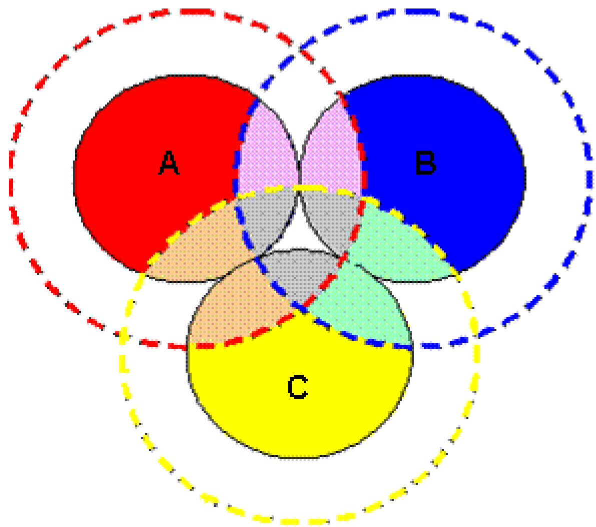
6.1 Reciprocal Coordinated Flowgates

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.



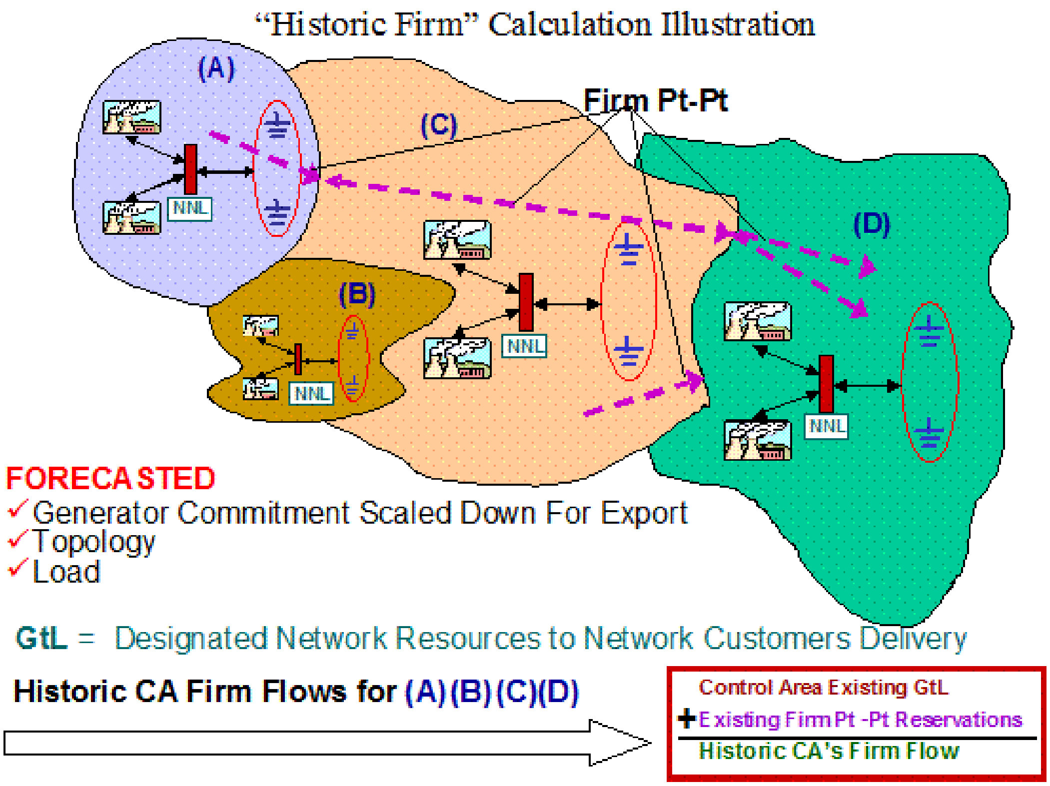
As shown in the illustration above, Operating Entity A, Operating Entity B and Operating Entity C each have their own set of Coordinated Flowgates (represented by the blue, yellow and red dotted-line circles). Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's, 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.



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	58 + (0.15 (-45)) = 58 + (-6.75) ≈ 58 + (-7) = 51

impacts (down to 0%) to obtain the weighted net Transmission Service impacts. The 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.

   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.

Section – 7 Appendices

Appendix A – Glossary

Agreement – Agreement shall mean this Minnkota-MISO Coordination and Operation Agreement, 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.

[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 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.

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

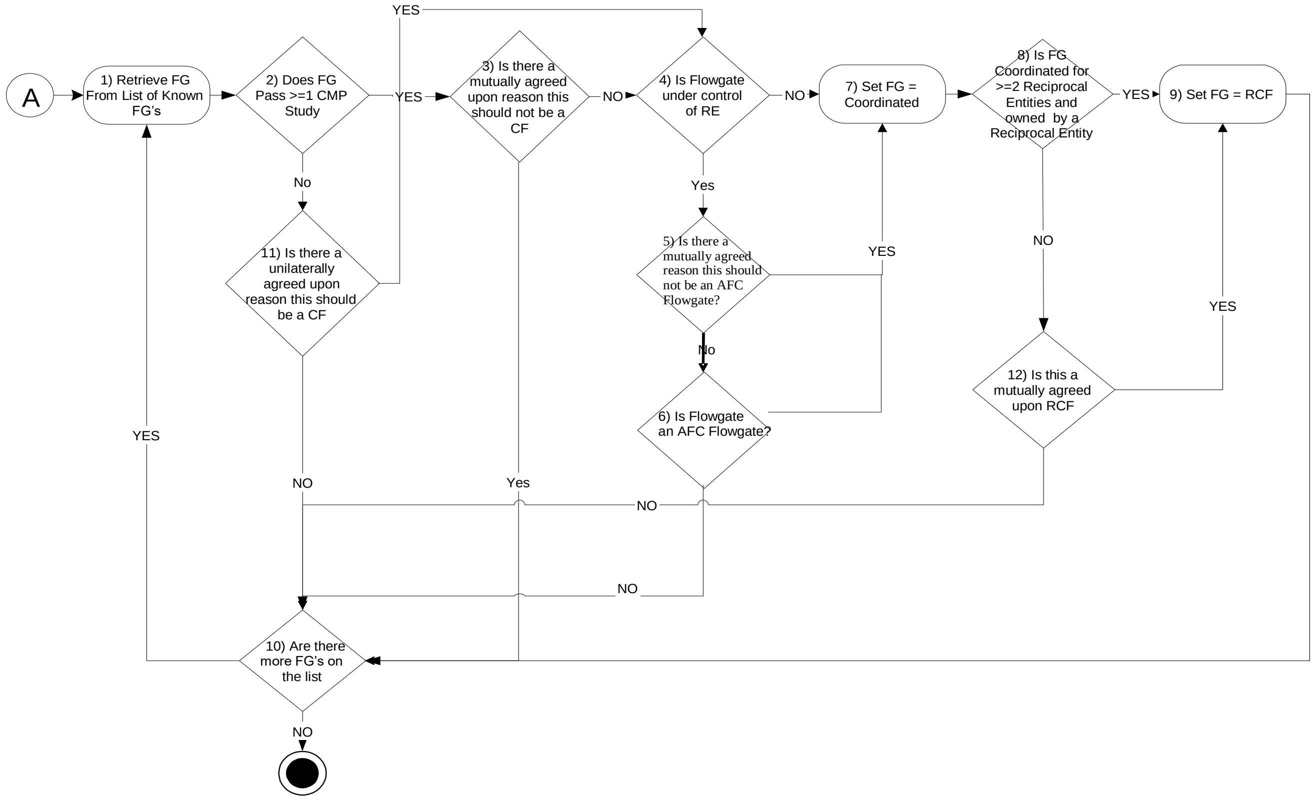


TABLE C-1

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.	
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	

Step	Activity	Requirements	Detailed Description	Additional Documentation
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.	
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

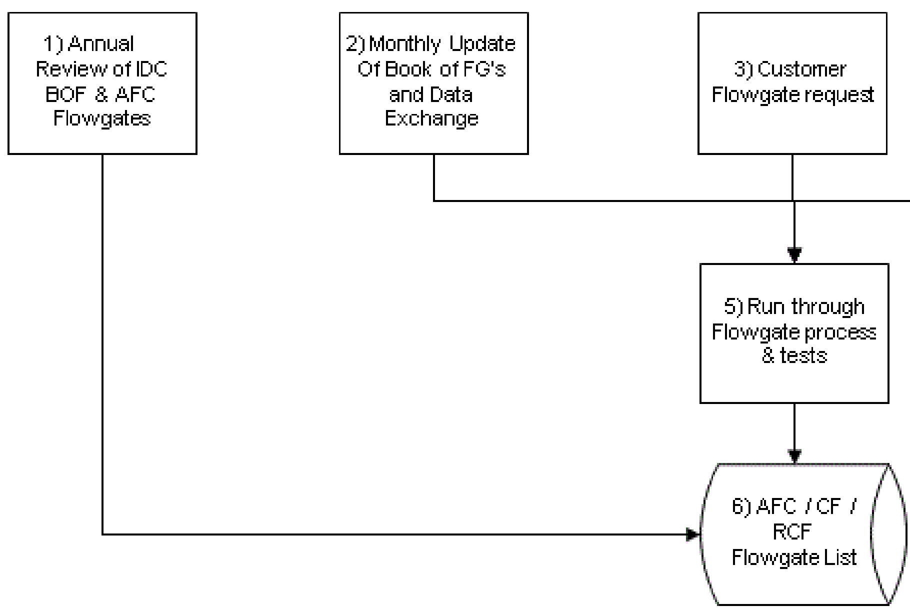


TABLE C-2

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.

Appendix I – Treatment of MHEX Flowgate

The extent of participation by Minnkota Power Cooperative, Inc. ("Minnkota") in the MISO Energy and Operating Reserve Markets ("Market"), and the financial settlement of such participation, are governed by the terms and conditions of settlement agreements entered into by Minnkota and MISO and other parties in 2005 and amended in 2008 ("Settlement Agreements"), and a coordination agreement entered into by Minnkota and MISO in 2015 ("Coordination Agreement"): (i) Minnkota offers its generation and bids its load into the MISO Market; (ii) Minnkota's loads and resources are balanced as part of the MISO LBA in which Minnkota loads and resources reside; (iii) Minnkota makes Off-System sales of its generation using its own transmission to deliver the energy without additional charges for service under the MISO Tariff; (iv) Minnkota is a Market Participant but is not subject to MISO Transmission Service Charges and Market Charges when Minnkota generators are used to serve Minnkota load (including Off-System loads) using Minnkota's transmission system. To accommodate these unique arrangements, which benefit both Minnkota and MISO through Minnkota's participation in the MISO Market, the following adjustments have been made to MISO's Market Flow calculations and historic Flowgate Allocations:

(c) A combined MISO Market Flow that reflects all generators within the MISO Market (including Minnkota generators) being used to serve all load within the MISO Market (including Minnkota load).

(d) A combined MISO historic Allocation that reflects MISO and Minnkota historic generation to load impacts and historic PTP impacts as of the Freeze Date utilized in the Allocation process.

As signatories to the MISO-Minnkota Coordination Agreement, MISO and Minnkota have agreed to honor a combined MISO-Minnkota firm Allocation on RCFs when selling Firm Transmission Service and that the Historic Firm Flow calculation of Minnkota shall be included with the Historic Firm Flow calculation of MISO to determine a combined MISO-Minnkota firm Allocation for RCFs. The only exception is the MHEX Flowgate (MHEX_S and MHEX_N) where MISO and Minnkota will maintain separate historic Allocations. The Minnkota and MISO Allocations of the MHEX Flowgate (U.S. portion) shall be defined by the Manitoba-U.S. Interface Transmission Capacity Rights Agreement.

Because of the uniqueness of the MHEX Flowgate (U.S. portion), where the contract path limit and the historic Allocation are the same, MISO and Minnkota have agreed to do capacity sharing in addition to Allocation sharing on this interface Flowgate. In recognition of the unique arrangements between Minnkota and MISO resulting from the Settlement Agreements, and because of Minnkota's willingness to do Allocation sharing/capacity sharing of the MHEX Flowgate as well as to do capacity sharing on the Bison-Maple River 345 kV line as documented in the MISO-Minnkota Coordination Agreement, MISO has agreed to an arrangement within the

MISO Markets that provides benefits to Minnkota that extend beyond its rights acknowledged in the Settlement Agreements (i.e., Minnkota has sufficient generation, transmission facilities, and contract rights to serve its load without using MISO's system and that MISO is not providing Transmission Service to Minnkota when Minnkota is exercising its rights to use its own transmission facilities and contract rights to serve its load). This arrangement does not exist with other Reciprocal Entities and is the reason Allocation sharing and capacity sharing on the MHEX Flowgate and the Bison-Maple River 345 kV line does not extend to other Reciprocal Entities.