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March 4, 2008

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

**Re: Midwest Independent Transmission System Operator, Inc., and Transmission Owners of the Midwest Independent Transmission System Operator, Inc. Revisions to Open Access Transmission and Energy Markets Tariff to Implement the Midwest ISO's Western Markets Proposal
Docket No. ER08-637-000**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1 *et seq.* (2007), the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") submits for filing six copies of proposed revisions to its Open Access Transmission and Energy Markets Tariff ("EMT" or "Tariff") to expand its Energy and Operating Reserve Markets.[1] The proposed changes will enhance reliability and "seams" coordination in the Midwest and will permit closer integration of members of the Mid-Continent Area Power Pool ("MAPP") and other utilities and market participants in the region into the Midwest ISO's Energy and Operating Reserves Markets.[2]

The Midwest ISO proposes an effective date of June 1, 2008, for this filing. As further discussed in Part VI of this transmittal letter, the Midwest ISO Transmission Owners ("Midwest ISO Transmission Owners" or "Transmission Owners")[3] possess the exclusive filing rights under

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[1] The capitalized terms that are not otherwise defined herein shall have the meaning as set forth in the Tariff or the revisions thereto proposed in this or other pending proceedings.

[2] This filing letter and the attached testimony refer to the Midwest ISO's submission in the instant proceeding as the "Western Markets Proposal."

[3] For purposes of this filing, the Midwest ISO Transmission Owners include: American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp.; Duke Energy Shared Services for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.;

Appendix K of the ISO Agreement[4] with respect to certain rate aspects of the Western Markets Proposal. To the extent these filing rights are implicated, the Midwest ISO Transmission Owners join the Midwest ISO in this submission.[5]

I. EXECUTIVE SUMMARY

Since its creation, the Midwest ISO has sought to extend its services and scope to utilities located in the upper and western regions of the Midwest through the provision of reliable and efficient system operations. Unlike other regional transmission organizations ("RTOs") that were formed on the basis of "tight" power pools, with long histories of regional cooperation and centralized dispatch, the Midwest ISO has faced unique challenges in building a successful regional energy market virtually from scratch. One such challenge has been to create the demand for the Midwest ISO's services and markets by transmission providers that are not yet ready to transfer their facilities under the Midwest ISO's functional control.

Although some of the utilities in the upper Midwest joined the Midwest ISO as Transmission Owners, many have declined to do so for a variety of reasons and remain unwilling or unable to take that step in the foreseeable future.[6] When approved by the Commission, the Western Markets Proposal will enable the Midwest ISO to provide enhanced reliability and "seams" management services on a broader, uniform basis, not only to parties in the MAPP region but also to other eligible customers. In addition, several MAPP parties and other interested entities that are not signatories to the ISO Agreement have concluded that the Midwest ISO's Energy and Operating Reserve Markets may provide substantial benefits to them in the event of their closer integration with the Midwest ISO. The Locational Marginal Price ("LMP")-based congestion management mechanisms and the efficient Security Constrained Economic Dispatch ("SCED") utilized in the Midwest ISO are of particular value to these customers, who

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Manitoba Hydro; Michigan Public Power Agency; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wabash Valley Power Association, Inc.

[4] The full name of the ISO Agreement is the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation. The ISO Agreement is on file with the Commission as Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1.

[5] Specifically, the Midwest ISO Transmission Owners join this submission solely to file Schedule 32 (Market Integration Transmission Service). The Midwest ISO Transmission Owners' support for Schedule 32 does not necessarily indicate support by each individual Transmission Owner for the entire filing. The Transmission Owners reserve the right to intervene and comment on the filing.

[6] In MAPP, these transmission providers were parties to various tariff administration, reliability, and "seams" management agreements with the Midwest ISO, which expired on February 1, 2008. Pending finalization and review of the Western Markets Proposal, the "seams" agreement has been extended on an interim basis and a new short term agreement to provide reliability coordination has been implemented, so that the Midwest ISO can continue providing these services to the MAPP region during the intervening period.

currently have to rely on far less efficient Transmission Loading Relief ("TLR") procedures to manage congestion.

The Western Markets Proposal represents a break-through that extends the benefits of the Midwest ISO's Energy and Operating Reserve Markets to a potentially large group of new customers while allowing them to remain transmission providers in their own footprints, thereby removing the principal obstacle to their fuller participation in the Midwest ISO. The Western Markets Proposal allows these entities and their customers to utilize the existing reliability services and offers market-to-non-market "seams" coordination service in a form that includes the opportunity to redispatch generation as an economic alternative to TLRs. It also extends the reach and benefits of the Midwest ISO's Energy and Operating Reserve Markets to footprints of other transmission providers.

The core of the Western Markets Proposal is contained in a new Module F of the Tariff, which has three major parts that correspond to the three types of Coordination Services proposed in this filing: (1) Reliability Coordination Service; (2) Interconnected Operations and Congestion Management Service; and (3) Market Coordination Service. While these Coordination Services are discussed in detail below, as well as the supporting testimony, they can be briefly summarized as follows:

- Reliability Coordination Service. Part I of proposed Module F addresses Reliability Coordination Service. This is the same reliability coordination service that the Midwest ISO currently provides to its Transmission Owners and to MAPP members, and it is now extended to all eligible customers. To be eligible, a customer must be a NERC-Registered Balancing Authority or NERC-Registered Transmission Operator. Because the Transmission Owners already receive comparable reliability coordination services from the Midwest ISO pursuant to the ISO Agreement and other Modules of the Tariff, they will not be eligible for Reliability Coordination Service as long as they remain signatories to the ISO Agreement. Reliability Coordination Service may be taken as a "stand-alone" service or in combination with Interconnected Operations and Congestion Management Service under Part II of Module F. A Market Coordination Customer taking service under Part III of Module F is required to take Reliability Coordination Service.

- Interconnected Operations and Congestion Management Service. Part II of proposed Module F addresses Interconnected Operations and Congestion Management Service. This service is intended to make available to all eligible customers the Midwest ISO's "seams" coordination services that are currently provided under individual "seams" coordination or joint operation agreements.[7]

[7] The Midwest ISO has a number of FERC-approved "seams" coordination agreements with neighboring systems, including MAPP. Generally, these agreements provide a mechanism to manage market-to-non-market

Importantly, the proposed Interconnected Operations and Congestion Management Service adds the option for redispatch of generation by the Midwest ISO or the non-market entity if that is economically superior to curtailment or other redispatch to meet a TLR obligation. To be eligible to receive Interconnected Operations and Congestion Management Service, a customer must be a NERC-Registered Transmission Provider providing service pursuant to an open access transmission tariff or other similar tariff over transmission facilities that are interconnected with the Midwest ISO's Transmission System or with the facilities of a Market Coordination Customer taking service under Part III of Module F. Interconnected Operations and Congestion Management Service may be taken as a stand-alone service or in combination with Reliability Coordination Service under Part I of Module F, but may not be combined with Market Coordination Service under Part III of Module F. A Congestion Management Customer may not be a signatory to the ISO Agreement.

- Market Coordination Service. Part III of proposed Module F addresses Market Coordination Service. This service extends the Midwest ISO's Energy and Operating Reserve Markets to the footprints of Market Coordination Customers by allowing them to integrate into the Midwest ISO's Energy and Operating Reserve Markets resources and loads interconnected with their designated transmission facilities while retaining the functional control of their transmission grid. To be eligible to receive Market Coordination Service, a customer must be a transmission provider providing transmission service on facilities that are: (i) interconnected with the facilities of a Transmission Owner; (ii) interconnected with the facilities of another Market Coordination Customer; or (iii) interconnected with the facilities of a Congestion Management Customer that offers a transmission service that is adequate to enable the Midwest ISO to provide the SCED. A Market Coordination Customer cannot be a signatory to the ISO Agreement and must take Reliability Coordination Service under Part I of Module F concurrently with its Part III service.

To complement Module F, certain additional Tariff revisions are proposed in this filing. By way of summary, these revisions include: three *pro forma* service agreements corresponding to each type of Coordination Services, Tariff Schedules providing the necessary mechanisms for determination of charges under Parts I and III of Module F, the standard CMP to be used in connection with the provision of service under Part II of Module F, and certain *pro forma* transmission service provisions that must be included in Market Coordination Customer transmission tariffs to enable the Midwest ISO to provide service under Part III of Module F. Other Tariff Modules (except portions of Module B dealing with traditional transmission service that will be provided under the tariff of the Market Coordination Customer) will be applicable to

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interfaces and specify an array of congestion management tools that are utilized for that purpose, including a standardized Congestion Management Process ("CMP").

customers taking service under Module F. The Midwest ISO also proposes a number of new definitions and various conforming changes throughout the Tariff.

The Western Markets Proposal is expected to produce substantial benefits. In their respective testimonies, Mr. T. Graham Edwards, the Chief Executive Officer ("CEO") of the Midwest ISO, and Mr. Clair J. Moeller, the Midwest ISO's Vice President of Transmission Assets, explain that the expected benefits include: (1) improved regional reliability; (2) more efficient congestion management procedures; (3) reduced administrative costs for existing Midwest ISO stakeholders; (4) increased revenues for Transmission Owners and lesser financial burdens on existing customers; and (5) additional new sources of power and more power supplies for the entire region.[8] The Western Markets Proposal is consistent with Order No. 2000[9] and is not expected to have any adverse effects on the current Midwest ISO membership or operations.[10]

Finally, the Midwest ISO's Ancillary Services Markets ("ASM") proposal, which has now been conditionally accepted by the Commission,[11] has a direct effect on the Midwest ISO's submission in this proceeding with respect to Market Coordination Service proposed under Part III of Module F. As explained by Mr. Moeller, while proposed Reliability Coordination Service and Interconnected Operations and Congestion Management Service can be provided even prior to the implementation of the ASM, Market Coordination Service may be provided only after the ASM proposal goes into effect.[12]

II. DESCRIPTION OF THE WESTERN MARKETS PROPOSAL

A. Background

As detailed by Mr. Moeller,[13] the origins of the Western Markets Proposal lie in the existing relationship between MAPP and the Midwest ISO. Both organizations have overlapping footprints and historically have maintained close ties in diverse areas, such as reliability coordination and "seams" management. Many MAPP members trade in the Midwest ISO markets and some MAPP transmission owners have transferred their facilities to Midwest ISO's functional control. The Western Markets Proposal seeks to take existing cooperation a step further, both by expanding the "menu" of available services and by bringing such services to a broader array of customers.

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8 *See* Prepared Direct Testimony of T. Graham Edwards, Ex. MISO-1 ("Edwards Testimony"), at 3-4; Prepared Direct Testimony of Clair J. Moeller, Ex. MISO-2 ("Moeller Testimony"), at 18-22.

9 *Regional Transmission Organizations, Order No. 2000,* FERC Stats & Regs ¶ 31,089 (1999), *order on reh'g, Order No. 2000-A,* FERC Stats & Regs ¶ 31,092 (2000).

10 *See* Edwards Testimony, at 4-8.

11 *See Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,172 (2008)("ASM Order").

12 *See* Moeller Testimony, at 10-11.

13 *See id.*, at 11-16.

MAPP was formed in 1972 as a "loose" power pool to provide reserve sharing and back-up generation for its members, but without the centralized dispatch that was more common in "tight" power pools in the east.[14] The Commission approved the original MAPP Agreement on June 15, 1977,[15] and a Restated Agreement was accepted for filing on September 12, 1996.[16] The Restated MAPP Agreement created a regional transmission group ("RTG"), established a NERC reliability council for MAPP, provided for generation and planning reserves coordination, included a regional transmission tariff for short-term point-to-point transmission service, known as "Schedule F," and provided for certain other functions and internal governance mechanisms. In 1999, the then-existing MAPP Schedule F was superseded by a regional open access short-term point-to-point transmission service tariff, which remains in effect.[17] In 1990, MAPPCOR, Inc. ("MAPPCOR") was incorporated as a not-for-profit organization to provide transmission and reliability services to the MAPP members as a contractor and to administer the MAPP Agreement.

After the Midwest ISO was formed as an independent system operator ("ISO") in 1998, some, but not all, MAPP transmission-owning members joined the Midwest ISO as Transmission Owners, requiring the two organizations to improve coordination and cooperation. In anticipation of the Midwest ISO's launch as the regional transmission service provider on February 1, 2002, the Midwest ISO purchased the majority of the MAPPCOR assets and entered into a Transmission Services Agreement ("TSA")[18] with MAPPCOR on December 1, 2001. Under the TSA, the Midwest ISO acted as the NERC Reliability Coordinator for the MAPP members that had not joined the Midwest ISO and provided related reliability coordination services.[19] When the TSA expired on February 1, 2008, a new, more detailed agreement specifically addressing reliability coordination services took its place. The Reliability Coordination Service proposed under Part I of Module F is patterned closely on the reliability coordination services the Midwest ISO provides under the new "Reliability Coordination Agreement between Contractor and Reliability Coordinator" dated January 23, 2008.

Similarly, MAPP and the Midwest ISO have cooperated with respect to "seams" management, which was put on the agenda by the Midwest ISO's launch of its Energy Markets on April 1, 2005. In anticipation of that date, discussions began in the region seeking to ensure that the benefits of market participation accrued to entities that had joined the Midwest ISO

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[14] *Mid-Continent Area Power Pool*, 48 FPC 607 (1972).

[15] *Mid-Continent Area Power Pool, Opinion No. 806, 58 FPC 2622, reh'g denied, Opinion No. 806-A, 59 FPC 1651 (1977), aff'd, sub. nom., Central Iowa Power Coop v. FERC, 606 F.2d 1156 (D.C. Cir. 1979).*

[16] *Mid-Continent Area Power Pool*, 76 FERC ¶ 61,261 (1996).

[17] *Mid-Continent Area Power Pool*, 87 FERC ¶ 61,075, *reh'g denied*, 89 FERC ¶ 61,135 (1999), *order on compliance*, 91 FERC ¶ 61,065 (2000).

[18] The full name of the Transmission Services Agreement was the Amended Agreement for Provision of Transmission-Related Services by the Midwest ISO to MAPPCOR.

[19] Originally, the Midwest ISO also provided staff support for MAPP committee activities and administered MAPP's regional tariff Schedule F, but in November 2007, MAPPCOR resumed the tariff administration for Schedule F and several key committee support functions, leaving reliability coordination as the primary service under the TSA.

while not placing a disproportionate burden on the non-market region. The Commission also encouraged the Midwest ISO to address comprehensively "seams" issues as a prelude to the initiation of its Energy Markets.[20] As a result, the Midwest ISO and MAPPCOR entered into a Seams Operating Agreement ("SOA") which was executed on January 31, 2004, accepted for filing on March 16, 2005,[21] and expired on February 1, 2008.[22]

In anticipation of the TSA's and the SOA's expiration, representatives of the Midwest ISO and MAPP began discussions in late 2007 to explore the contours of their prospective relationship. While still unwilling or unable to join the Midwest ISO as Transmission Owners, many MAPP members saw substantial benefits accruing not only from the continuation of the Midwest ISO's traditional reliability and seams coordination, but also from the operation of the Midwest ISO's proposed Energy and Operating Reserve Markets and the consequent LMP-based congestion management tools made possible.[23] In the spirit of the open architecture that has been a hallmark of the Midwest ISO, the parties have jointly developed Module F to provide a flexible menu of options for entities that are not ready to become Transmission Owners, but want to obtain reliability coordination and/or congestion management services from the Midwest ISO or if they so choose, join and participate in the Midwest ISO Energy and Operating Reserve Markets.[24]

Finally, it is important to note that although the idea of Module F was rooted in negotiations with MAPP, whose members actively participated in the development of this filing,

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20 In its order approving the design of the Midwest ISO markets, the Commission stated: "[T]hough we agree with the Midwest ISO that the absence of seams agreements should not impede market startup, the markets cannot start without the Midwest ISO having at least a specific, transparent plan for how it will handle the interface of multiple transmission tariffs and market-to-non-market seams. We encourage market participants to use the PJM-Midwest ISO JOA as a model or starting point for seams agreements, particularly with respect to the seams with the various utilities in the MAPP region[.]" *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163, P. 639 (2004).

21 *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,290 (2005).

22 The substantive provisions of the SOA established protocols for the exchange of real-time data and projected information; allowed the parties to coordinate and exchange calculations of total transfer capability ("TTC"), available transmission capability ("ATC") and available flowgate capability ("AFC"); provided for reciprocal coordination of flowgates through a binding congestion management process ("CMP"); and provided for market redispatch to offset the effects of loop flow.

23 Under the SOA, redispatch of market flows is available for congestion management, but most relief is secured through TLR orders. As the Commission has recognized on numerous occasions, these are blunt instruments that impose significant costs on parties to energy transactions. *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236, PP 30 and 32 (2004) ("[R]eliance on TLRs for congestion management inherently leaves transmission capacity under-utilized because the TLR approach relies on imprecise flow estimates" and "each TLR curtailment . . . may curtail too many or too few transactions." The uncertainty of the TLR process undermines the reliability of the grid because it made it "more difficult to maintain power flows within operating security limits.")

24 As noted above, the Midwest ISO also has negotiated a "bridge" agreement with MAPPCOR to ensure that the reliability coordination services continue without interruption, and has agreed to extend the formal termination of the SOA to provide congestion management after the expiration of the TSA and the SOA, pending the approval and implementation of Module F.

the services offered would not be limited to MAPP members. Instead, each of the proposed Coordination Services in Module F will be available to all eligible customers. As explained below, the Midwest ISO has consulted with a broad array of stakeholders, including its Transmission Owners, with respect to this proposal.

B. Proposed Coordination Services

1. Reliability Coordination Service

a. Eligibility

To be eligible for service under Part I of Module F, a Reliability Coordination Customer must be an operating entity that is: (i) a Market Coordination Customer taking service under Part III of Module F or (ii) a NERC Registered Balancing Authority or a NERC Registered Transmission Operator that is not a signatory to the ISO Agreement at the same time it receives service under Module F. As a condition for obtaining service, the Reliability Coordination Customer is required to execute a Service Agreement and provide to the Midwest ISO certain essential operating information.

b. Nature of Service

Under Part I of Module F, the Midwest ISO is required to continuously maintain its status as Reliability Coordinator with NERC and to act as the Reliability Coordinator of the Reliability Coordination Customer Transmission Facilities throughout the term of its Service Agreement with the Reliability Coordination Customer. In general, Reliability Coordination Service consists of the specific tasks and functions required of Reliability Coordinators by the NERC Reliability Standards, as they may be amended from time to time. The principal tasks include, but are not limited to, the following: (i) monitoring of the Reliability Coordination Customer Transmission Facilities to ensure operational reliability of the Combined Reliability Systems; (ii) providing on-line network modeling using state estimation and real-time contingency analysis in the operating time frame; (iii) providing operations engineering services, such as analyses of the Combined Reliability Systems' adequacy and security for day-ahead operations, conducting voltage collapse studies when requested, and support for Operating Guides as needed; (iv) monitoring and advising the Reliability Coordination Customer of voltage support and supplies of reactive power; (v) monitoring and assessing abnormal Reliability Coordination Customer ACE deviations and system frequency deviations; (vi) using TLR procedures to relieve actual or potential operating security limit violations; (vii) supporting power system restoration activities; (viii) supporting transmission map maintenance for the Reliability Coordination Customer Transmission Facilities; and (ix) monitoring the Reliability Coordination Customer's compliance with applicable NERC and Regional Entity standards and supporting such compliance with data as required.

As the Reliability Coordinator, the Midwest ISO will have the authority to monitor and direct the Reliability Coordination Customer's actions with respect to the Reliability Coordination Customer Transmission Facilities in order to preserve the integrity and reliability of the Bulk Electric System and to ensure that operating parameters are maintained in accord with NERC and Regional Entity standards. The Midwest ISO will periodically perform load-flow and stability studies of the Reliability Coordination Customer Transmission Facilities to identify and address reliability problems; will be responsible for the exchange of operating information related to the Reliability Coordination Customer Transmission Facilities with adjoining Reliability Coordinators and other operating entities within the Combined Reliability Systems that require Reliability Coordination Customer operational data for reliability-related purposes or for calculation of ATC and its components; and will develop, for approval by the NERC Operating Committee, a regional reliability plan and procedures for responding to emergencies that include the Reliability Coordination Customer Transmission Facilities.

For the purposes of mitigating an Interconnection Reliability Operating Limit ("IROL") violation or a System Operating Limit ("SOL") violation so as to return the Combined Reliability Systems to a reliable state, the Midwest ISO will have authority to direct the Reliability Coordination Customer to: (i) redispatch generating facilities interconnected to the Combined Reliability Systems in specified circumstances; (ii) reconfigure the Reliability Coordination Customer Transmission Facilities, including requiring changes to the transmission maintenance and outage schedules of the Reliability Coordination Customer; (iii) modify interchange; (iv) reduce load to mitigate a critical condition, up to and including shedding of firm load; (v) direct actions to be taken by transmission operators, balancing authorities, generator operators, transmission service providers, load-serving entities, and purchasing-selling entities within the Combined Reliability Systems to preserve the integrity and reliability of the Combined Reliability Systems, which are required to be taken without delay, but within no longer than 30 minutes; and (vi) initiate the control action or emergency procedure necessary to relieve a potential or actual IROL violation within stated time limits. The Reliability Coordination Customer is required to comply with the Midwest ISO's directives issued to mitigate an IROL or SOL violation, consistent with the Operating Guides for the Reliability Coordination Customer Transmission Facilities. The Midwest ISO's authority to direct these actions is limited to circumstances where such action is necessary to prevent or manage emergency situations and is subject to existing operating restrictions on transmission facilities and existing operating and environmental restrictions that limit a generator's ability to change its dispatch.

The Reliability Coordination Customer will retain the authority to receive, confirm, and implement interchange and other transmission service schedules, subject to the Midwest ISO's authority to modify interchange. While it will not have authority to institute a TLR or EEA, the Reliability Coordination Customer may request that the Transmission Provider take such action.

c. Reliability Coordination Customer Obligations

Under Part I of Module F, the Reliability Coordination Customer is required to notify the Midwest ISO without undue delay of any operating difficulty that could prevent the Reliability Coordination Customer from understanding and communicating to the Midwest ISO the real time conditions existing in the Reliability Coordination Customer's balancing authority area or transmission system. The Reliability Coordination Customer also is required to comply with the operating policies and reliability standards of NERC and of the applicable Regional Entity. In the event that NERC or a Regional Entity conducts an audit of the Reliability Coordination Customer's balancing authority or transmission operation or facilities during the term of the Service Agreement, the Reliability Coordination Customer is required to implement, without undue delay, all reasonable mitigation or remedial measures required to address deficiencies, if any, identified by such reliability or similar audit.

Concurrently with its execution of its Service Agreement, the Reliability Coordination Customer is required provide the Midwest ISO with all such information as is reasonably necessary for the Midwest ISO to provide the Reliability Coordination Service. The Reliability Coordination Customer is also responsible for developing, maintaining and implementing a set of plans to mitigate operating emergencies and for developing a system restoration plan for the Reliability Coordination Customer Transmission Facilities that is consistent with the Transmission Provider's Reliability Coordinator Area system restoration plan.

Unless otherwise agreed, the Reliability Coordination Customer is required to submit its transmission and generation facility maintenance and outage schedules to the Midwest ISO in accordance with existing Midwest ISO outage coordination procedures. The Midwest ISO may disapprove or revise these transmission and generation schedules if they fail to meet established reliability standards or if necessary to respond to emergency conditions.

d. Term

The Midwest ISO proposes that the initial term of Reliability Coordination Service be for a period of three years. The Service Agreement will be automatically renewed for successive one year terms and may be terminated upon one year's notice. One exception to this requirement is that public power entities are permitted to terminate Reliability Coordination Service on shorter notice if the Tariff is modified in a manner that causes a conflict with state law, regulations, or rate schedules of the public power entity.[25]

[25] The public power exceptions in proposed Section 12E are based on existing Section 12D of the Tariff, which was approved by the Commission in 2003 as Section 41 of the Midwest ISO's then-effective OATT to facilitate the participation of Nebraska utilities in the proposed TRANSLink Appendix I ITC. *See Midwest Independent Transmission System Operator, Inc.*, 103 FERC ¶ 61,207 (2003).

e. Congestion Management

Under Part I of Module F, the Midwest ISO will use the then-current NERC TLR procedures and related NAESB business practices to mitigate congestion on the Reliability Coordination Customer Transmission Facilities. If the Reliability Coordination Service under Part I of Module F is combined with the Interconnected Operations and Congestion Management Service under Part II of Module F, then the congestion management procedures under Part II of Module F are used. The congestion management procedures set forth in Part I of Module F are not applicable to customers that take combined service under Parts I and III of Module F because the Midwest ISO's SCED is used to relieve congestion on such customers' facilities.

f. Compensation and Billing for Reliability Coordination Service

In general, the Midwest ISO proposes that the charge for Reliability Coordination Service under Part I of Module F, the Reliability Coordination Cost Recovery Adder, be the portion of Tariff Schedule 10 fees[26] that are attributable to the reliability coordination functions performed by the Midwest ISO. This portion is currently estimated to be approximately 51 percent of the Schedule 10 fees. The Reliability Coordination Cost Recovery Adder is set forth in proposed Schedule 31 of the Tariff. Mr. Michael P. Holstein, the Midwest ISO's Chief Financial Officer, explains how the Reliability Coordination Cost Recovery Adder is derived in his Prepared Direct Testimony, which is included in this filing as Exhibit MISO-3.[27] The Midwest ISO will bill Reliability Coordination Customers on a monthly basis pursuant to the procedures set forth in proposed Section 7.19 of the Tariff.[28]

g. Withdrawal Fee Obligation for Reliability Coordination Customers

Reliability Coordination Customers will be required to pay a withdrawal fee upon termination of their Service Agreement with the Midwest ISO. In general, proposed Section 77.3 of the Tariff requires the withdrawing customer to pay an allocated share of the remaining book value of all incremental capital assets associated with the provision of the services under Part I of Module F and the applicable Service Agreement that are under development or in-service as of the termination date including certain financing costs associated with such assets. Mr. Holstein provides further specifics with respect to how the withdrawal payment is determined.[29]

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26 Schedule 10 of the Tariff contains the Midwest ISO's Cost Recovery Adder.
27 Prepared Direct Testimony of Michael P. Holstein, Ex. MISO-3 ("Holstein Testimony"), at 3-5.
28 *Id.* at 6-7.
29 *Id.* at 7-9

h. Reliability Coordination Technical Committee

Part I of Module F also provides for a Reliability Coordination Technical Committee ("RCTC"), which will be composed of representatives of the Midwest ISO and of all Reliability Coordination Customers. The RCTC is designed as an advisory technical committee and will not a part of the formal stakeholder governance process. Any recommendations for changes to Part I service would be tariff changes, and would be reviewed by the appropriate Midwest ISO stakeholder committees prior to any filing. The Midwest ISO and the Reliability Coordination Customers retain their rights under Sections 205 and 206 of the FPA.

2. Interconnected Operations and Congestion Management Service

a. Eligibility

To be eligible for Interconnected Operations and Congestion Management Service under Part II of Module F, a Congestion Management Customer must be a NERC Registered Transmission Provider providing reciprocal transmission service using transmission facilities that are physically connected to the Midwest ISO's Transmission System or to the transmission facilities of an entity taking service under Part III of Module F of the Tariff. A Congestion Management Customer may not be a signatory to the ISO Agreement because congestion management is achieved using the SCED for Transmission Owning members of the Midwest ISO. As a condition to obtaining service, the Congestion Management Customer is required to execute a Service Agreement under Part II of Module F and provide certain required information to the Midwest ISO.

b. Nature of Service

Interconnected Operations and Congestion Management Service is designed for "seams" management between market and non-market areas and is based on a standard, FERC-approved CMP. The terms of Part II of Module F are taken, in a large part, from the existing MAPP Seams Operating Agreement, with the exception of the newly created redispatch provisions. The CMP found in proposed Attachment LL is identical to the recently standardized CMP approved by the Commission in two other Midwest ISO seams agreements.

Interconnection Operations and Congestion Management Service involves the following major components and obligations:

- Transfer of Information and Data. The Midwest ISO and the Congestion Management Customer are obligated to transfer to each other the following types of data and information: (a) Real-Time and Projected Operating Data; (b) SCADA Data; (c) EMS Models; and (d) Operations Planning Data. Section 80 of the Tariff details the specific data items for each category and establishes necessary rules for the exchange.

- TTC/ATC/AFC Protocols. The Midwest ISO and each Congestion Management Customer will establish a TTC/ATC/AFC Protocol, which will be included in the customer's Service Agreement executed under Part II of Module F, to coordinate their TTC/ATC/AFC calculation models. The Midwest ISO and the Congestion Management Customer will provide each other with various generation, transmission, load, outage and interchange data and will coordinate their transmission service requests.

- Reciprocal Coordination of Flowgates. To coordinate congestion management proactively, the Midwest ISO and the Congestion Management Customer will be obligated to respect each other's determinations of AFC/ATC and curtailment priorities for real-time operations applicable to their Coordinated Flowgates ("CFs"). Additionally, the Midwest ISO and the Congestion Management Customer will be obligated to respect the allocations defined by the reciprocal allocation process set forth in the Congestion Management Process, which is included in this filing as proposed Attachment LL to the Tariff. The Midwest ISO will utilize its Unit Dispatch System ("UDS") and Security-Constrained Unit Commitment ("SCUC") in effect at the time to manage the portion of the flows on an RCF allocated to the Midwest ISO. The Congestion Management Customer's Reliability Coordinator will utilize NERC TLR process to manage the portion of the flows on an RCF allocated to the Congestion Management Customer.

- Generation Redispatch. Part II of Module F contains a generation redispatch obligation that makes it unique among other seams agreements. Under Part II of Module F, the Midwest ISO and the Congestion Management Customer may confer to identify: (i) transmission operating constraints that could result in TLR or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation controlled by the Congestion Management Customer, and (ii) the generation units on the Congestion Management Customer's system, the redispatch of which would alleviate the identified transmission constraints. Where such redispatch opportunities are identified, Sections 83.3 and 83.4 of the Tariff describe the procedures applicable to such generation redispatch and the applicable compensation. These provisions have been closely modeled on the voluntary redispatch procedures that the Commission approved for the Redispatch Agreement between the Midwest ISO and East Kentucky Power Cooperative.[30] The chief distinction in this proposal is that the redispatch obligations in Part II of Module F are not voluntary, but, once the parties mutually agree to designate a target flowgate and develop applicable operating procedures, must be offered

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[30] *See Midwest Independent Transmission System Operator, Inc.*, 119 FERC ¶ 61,338 (2007).

(subject to certain legal and reliability limitations) by the respective parties if the redispatch price is lower than the cost of relieving the congestion using traditional TLR or other redispatch solutions. In some cases, in order to effect the redispatch solution, it may be necessary for the Congestion Management Customer to purchase energy from the Midwest ISO market. Section 83.3.4 requires mutual agreement that such energy will be available and deliverable, and that the energy purchase will not create adverse conditions on the systems of either party. This section provides a mechanism to avoid redispatch that could result in scarcity pricing in the Midwest ISO market.

- Additional Coordination. The Midwest ISO and the Congestion Management Customer will also engage in: voltage control and reactive power coordination, regional transmission and generation outage coordination, planning coordination and reserve sharing coordination.

c. Term

The Midwest ISO proposes that the initial term of Interconnected Operations and Congestion Management Service under Part II of Module F be for a period of three years. The Part II Service Agreement will be automatically renewed for successive one year terms after the effective date of the Part II Service Agreement and may be terminated upon one year notice. An exception to this requirement is that public power entities are permitted to terminate Interconnected Operations and Congestion Management Service on shorter notice if the Midwest ISO's Tariff is modified in a manner that causes a conflict with state law, regulations, or rate schedules of the public power entity.[31]

d. Compensation

Mr. Holstein explains that any costs incurred to provide Interconnected Operations and Congestion Management Service will be allocated to and recovered under current Tariff Schedule 17 – Energy Market Administrative Cost Recovery Adder. Other than the redispatch provisions described above, there is no separate compensation or cost recovery mechanism for this proposed service.[32]

3. Market Coordination Service

a. Eligibility

To be eligible for service under Part III of Module F, a Market Coordination Customer must be a transmission provider providing transmission service on facilities that are: (i)

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[31] See n. 25, *supra*.
[32] Holstein Testimony, at 5-6.

interconnected with the facilities of a Transmission Owner; (ii) interconnected with the facilities of another entity taking service pursuant to this Part III; or (iii) interconnected with the facilities of certain Congestion Management Customers taking service under Part II of Module F. The intent of these eligibility requirements is to capture one or more of the situations that will ensure an electrical path sufficient to permit the Midwest ISO to dispatch resources and loads using the SCED and perform its Balancing Authority obligations. Further, service under Part III of Module F can only be taken in combination with Reliability Coordination Service under Part I of Module F. This requirement aligns Market Coordination Customers with existing Transmission Owners who now obtain reliability coordination service under the Tariff and it will ensure reliable operation of the Energy and Operating Reserve Markets by combining these related functions in one operation. Finally, signatories to the ISO Agreement are not eligible for Market Coordination Service, as long as they remain Transmission Owners of the Midwest ISO.

b. Nature of Service

The purpose of Market Coordination Service is to extend the Midwest ISO's market footprint to the transmission systems of Market Coordination Customers while leaving the provision of transmission service over these systems in the hands of those customers. The Midwest ISO will integrate the resources and loads in the Customer Zone with the Energy and Operating Reserve Markets by including the Market Coordination Customer Transmission Facilities, and loads and resources in the Customer Zone in the Midwest ISO's Network Model and Commercial Model. Further, the requirements set forth in Module C of the Tariff are applicable to all resources and loads in the Customer Zone, which must register as Market Participants (including resources and loads Pseudo Tied into, but excluding those Pseudo Tied out of, the Midwest ISO Balancing Authority) Market Coordination Customers will be participating in the ASM market and thus the Midwest ISO will become the Balancing Authority for those customers. Section 90.2.5 sets forth specific requirements in this regard, including the requirement that all loads and resources in the Customer Zone must either register as Market Participants to facilitate this function or make alternative arrangements to obtain Balancing Authority service from another entity. The Midwest ISO will manage transmission congestion in the Market Provider Region using its SCED, which includes redispatching Generation Resources as set forth in Module C of the Tariff. A specific exception to this process is the North Dakota Export ("NDEX") flowgate. Module F provides that the current congestion management system in place for NDEX under the current MAPP seams agreement will continue.

c. Eligibility for ARRs/FTRs/LTTRs

As set forth in proposed Section 90.2.3, transmission customers of a Market Coordination Customer will be eligible to receive ARR Entitlements under Module C of the Midwest ISO tariff, provided they are taking firm service comparable to that provided by the Midwest ISO under its Tariff, have entered into a long-term agreement for firm transmission service on the system of the Market Coordination Customer, timely submit necessary information, and meet the other requirements of the Tariff and Business Practices Manuals. In addition, the customers of the Market Coordination Customer may be eligible to participate in the Stage 1A allocation of ARRs (*i.e.*, Long Term Transmission Rights or "LTTRs") if such customers participate in the transmission planning and expansion process of the Market Coordination Customer, under terms that seek to ensure that its transmission system can support the simultaneous feasibility of all Stage 1A ARRs for their full term, consistent with the Commission's requirements for LTTRs. Mr. Richard Doying, the Midwest ISO's Vice President of Market Operation, explains in detail the proposed allocation of ARRs and FTRs in his Prepared Direct Testimony.[33]

d. Preexisting Contracts

Some of the Market Coordination Customers' preexisting contractual arrangements for transmission service will need to be modified as a precondition to receiving service under Part III of Module F. Specifically, proposed Section 90.2.4.1 provides that, if an eligible customer applies for Part III service and is a party to an existing "Carved-Out GFA" with a Midwest ISO Transmission Owner or another Market Coordination Customer, as listed in Attachment P of the Tariff, that applicant will be required, as a precondition to receiving under Part III of Module F, to convert its rights to Option A or Option C treatment (as defined in Module C of the Midwest ISO Tariff) or to tariff service under the appropriate tariff(s). As Mr. Doying explains, the reason for this requirement is straightforward: a Carved-Out GFA that has Midwest ISO Transmission Owner(s) and Market Coordination Customer(s) as parties is incompatible with participation in the Midwest ISO's Energy and Operating Reserve Markets.[34]

In addition, the Midwest ISO proposes a process to ensure that other preexisting contractual arrangements (*i.e.*, those that are not currently listed in Attachment P as GFAs) are identified by the Market Coordination Customers, and are given the appropriate GFA treatment. The GFA treatments selected by Market Coordination Customers for their preexisting agreements will be reviewed by the Midwest ISO pursuant to the criteria and process that are similar to that applied in the GFA proceeding at the inception of the Midwest ISO's Energy Markets in 2004-05. Such preexisting agreements that are subject to the "just and reasonable" standard of review are required to select either Option A or C GFA treatment, or full conversion to service under the EMT and/or under the Market Coordination Customer's tariff. Other such agreements are eligible to be classified as Carved-Out GFAs under the EMT if they are: (1) subject to the "public interest" standard of review; (2) silent on the applicable standard of review; or (3) contracts for the provision of transmission service by an entity that is not a public utility. Although such agreements are eligible to be classified as Carved-Out GFAs, the parties may voluntarily select Option A or C GFA treatment, or conversion to service under EMT and/or under the Market Coordination Customer's tariff. Upon such voluntary conversion, the GFA can no longer revert to carved-out status. On the other hand, preexisting agreements that are eligible to be carved out and choose to remain in that status shall be treated like other Carved-Out GFAs,

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33 Prepared Direct Testimony of Richard Doying, Ex. MISO-4 ("Doying Testimony"), at 3-8.

34 *Id.* at 10-11.

with one difference. If there is any inadequacy in the revenue needed to cover the congestion costs of such carved-out preexisting agreements, the revenue inadequacy will not be funded by the shortfall's allocation to all Market Participants across the Midwest ISO's Region, but instead shall be assessed on the load in the relevant Customer Zone that is not served under a preexisting agreement. Mr. Doying explains in detail the proposed preexisting contract arrangements and procedures in his testimony.[35]

e. Market Integration Transmission Service

The transmission arrangements that are needed to accommodate a single energy market over diverse transmission service footprints are quite complex. As explained by Mr. Moeller, the key element of these arrangements is Market Integration Transmission Service ("MITS").[36] MITS is a unique firm transmission service that shares certain attributes of network service from resources located in one transmission provider's footprint to serve loads in another transmission provider's footprint. MITS will be provided by the Midwest ISO over its footprint, as set forth in proposed Section 93.1 and Schedule 32 of the Tariff. Market Coordination Customers will provide a comparable version of MITS over their transmission systems, under the provisions that they will adopt in their own transmission tariffs pursuant to proposed Attachment MM. The Midwest ISO and Market Coordination Customers also may use other types of transmission service available under their respective tariffs to complete bilateral transactions.

In his testimony, Mr. Moeller explains that for transmission service sourced in the Midwest ISO, MITS will provide the necessary vehicle for market flows from the Midwest ISO Transmission System to a Market Coordination Customer's transmission system.[37] From the border, transmission service would be provided on the Market Coordination Customer's transmission system under the terms of that customer's tariff. For transmission service that is sourced in the Market Coordination Customer's footprint and sinks either in the Midwest ISO's footprint or another Market Coordination Customer's footprint, each Market Coordination Customer will be required to adopt comparable provisions in its transmission tariff, as set forth in proposed Attachment MM.[38] The adopted provisions will set the terms and conditions for: (1) the transmission service necessary for energy market flows from the Market Coordination Customer's transmission system to the Midwest ISO and (2) the transmission service for "drive through" flows across the transmission system of another Market Coordination Customer, to the extent flows are related to the Midwest ISO Energy and Operating Reserve Markets SCED. The transmission service within the Midwest ISO transmission system for energy flowing from the Market Coordination Customer's transmission system would be provided under MITS or other types of Transmission Service.

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[35] *Id.* at 8-14.
[36] Moeller Testimony, at 28.
[37] *Id.* at 28-29.
[38] *Id.* at 29-30.

Mr. Moeller further explains that MITS is needed because the standard transmission services offered under the *pro forma* OATT, the point-to-point transmission service and the network integration transmission service, cannot be used to accommodate the proposed market design.[39] Due to its unique characteristics, it will not be necessary to request, schedule, or tag MITS or post or decrement on the OASIS the ATC or AFC associated with MITS.[40] Further, MITS is not intended to replace or convert existing transmission service between Market Coordination Customers and customers within the Midwest ISO Tariff footprint. Nor will a separate service agreement be necessary to receive MITS.[41]

The MITS charge is set forth in proposed Schedule 32. As described by Mr. Moeller,[42] the MITS charge is not transaction-based and is designed to recover the Midwest ISO Transmission Owners' current "out" revenue requirement from Market Coordination Customers in proportion to their historic (previous year's) share of the net hourly real-time exports from resources located in the Midwest ISO footprint and that sink in that entity's balancing authority. A three-year Transition Period is proposed for the MITS charges under Schedule 32 because the actual market flows needed to develop the MITS charge can only be determined following the integration of the Market Coordination Customer's resources and loads into the real-time Energy and Operating Reserve Market and, for that reason, some transitional period of time is necessary to obtain the required actual flow data.[43] Each Market Coordination Customer will be responsible for the applicable Midwest ISO MITS transmission charges, but is free to establish a means to recover these charges from entities on its transmission system. The Midwest ISO's MITS revenues will be distributed to Transmission Owners by using existing revenue distribution mechanisms.

The MITS charge for a Market Coordination Customer for each year during the Transition Period is equal to charges collected at the External Transaction Delivery Point for Point-To-Point Transmission Service and its applicable schedules that represent an Export to the Market Coordination Customer during the calendar year prior to the effective date of the Market Coordination Customer's Service Agreement executed under Part III of Module F.[44] However, if the MITS charge for any year during the Transition Period equals zero for any Market Coordination Customer, the Transition Period will not apply to such a customer. Instead, the MITS charge for that customer will be calculated based on the methodology for post Transition Period charges. The applicable MITS charge is then prorated on a monthly basis and reduced by any monthly charges collected at the Internal Delivery Points for Point-To-Point Transmission Service and its applicable schedules that represent a delivery to the Market Coordination Customer at the Internal Delivery Points.

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[39] *Id.* at 30-31.
[40] *Id.* at 30.
[41] *Id.*
[42] *Id.* at 31.
[43] *Id.* at 31-32.
[44] *Id.* at 32-33.

After the Transition Period ends, the Midwest ISO will determine the applicable MITS charge through an algorithm set forth in Part B of Schedule 32. First, the Midwest ISO will determine the average hourly usage by a Market Coordination Customer by summing the positive hourly demand over the previous calendar year from the Transmission System to the Market Coordination Customer's transmission system and dividing this annual sum by the number of hours in a year.[45] In the first step, the Midwest ISO will reduce each positive hourly MITS demand by the amount of reserved Point-To-Point Transmission Service that coincides with that same hour and it is to an Internal Delivery Point(s) that represents delivery to that Market Coordination Customer at such Internal Delivery Point(s). Second, the Midwest ISO will determine the applicable single system-wide rate for MITS service. This rate will consist of: (1) the undiscounted Schedule 7 Drive Through and Out Rate in $/MW-YR; and (2) Schedule 1, 2, and 26 charges and any other Tariff schedules applicable to Point-To-Point Transmission Service. The rate is calculated using the formula set forth in the generic Attachment O of the Tariff (Transmission Provider Formulaic Rate Description), pages 1 and 2, and recalculated whenever any Transmission Owner updates its revenue requirement calculation, at a minimum twice each year on January 1 and June 1. Third, the Midwest ISO will calculate a charge for MITS for each Market Coordination Customer by multiplying the applicable Single - System Wide Rate by the average hourly usage determined above in the first step.

Outside of the Midwest ISO footprint, each Market Coordination Customer would determine its own charge for service over its facilities and provide the mechanism to allocate that charge to customers on its system. In the proposed Attachment MM, the Midwest ISO establishes certain *pro forma* provisions that all Market Coordination Customers must agree to include in their tariffs as a precondition for being eligible to receive service under Part III of Module F. These *pro forma* provisions represent the necessary minimum safeguards to ensure that the Midwest ISO may provide Market Coordination Service efficiently and without disruption. Although each Market Coordination Customer may further expand these provisions when they are adopted in its tariff, all such amendments should be consistent with or comparable to the original language set forth in Attachment MM.

f. Compensation and Billing for Market Coordination Service

The MITS charges, together with all other applicable charges under the Tariff will constitute compensation for Market Coordination Service. The Midwest ISO will bill Market Coordination Customers pursuant to the procedures set forth in proposed Section 7.21 of the Tariff.[46]

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[45] For the purposes of this calculation a negative hourly demand is set to zero.
[46] Holstein Testimony, at 6.

g. Withdrawal Fee Obligation for Energy and Operating Reserve Market Coordination Customers

Customers under Part III of Module F are required to pay a withdrawal fee upon termination of their Service Agreement with the Midwest ISO. In general, the withdrawing customer will be responsible for payment of: (a) an allocated share of the remaining book value of all Incremental Reliability Coordination Assets, and (b) an allocated share of the remaining book value of all incremental capital assets associated with the provision of Market Coordination Service and for certain financing costs associated with those assets. Mr. Holstein provides further specifics with respect to how the withdrawal payment is determined.[47]

h. Joint Coordination Committee

Part III of Module F also provides for a Joint Coordination Committee ("JCC"), which will be composed of representatives of the Midwest ISO and of all Market Coordination Customers. The functions of the JCC will be advisory only. Any suggestions for tariff changes to Part III, Module F would be handled as other tariff changes in the Midwest ISO stakeholder process prior to filing with the Commission. The Midwest ISO and the Market Coordination Customers retain their rights under Sections 205 and 206 of the FPA. Market Coordination Customers are eligible to participate in the existing stakeholder process in the "Coordination Customer" segment. Today, only Manitoba Hydro occupies this seat, and Manitoba Hydro has agreed that Market Coordination Customers share sufficient characteristics to logically inhabit this segment.

4. <u>Other Revisions</u>

To enable the Midwest ISO to provide the Coordination Services set forth in Module F, a number of additional Tariff changes are proposed. The key revisions are as follows:

a. Module A Revisions

Module A of the Tariff contains definitions and general provisions. The Midwest ISO proposes to amend the definitional portion of Module A to include the defined terms used in Module F. The Midwest ISO also proposes revisions to Article 7 of the Tariff to provide for billing procedures for the three types of Coordination Customers under Module F. As previously noted, the Midwest ISO has included new Section 12E to address issues that are unique to public power entities' participation in Module F.

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47 *Id.* at 9.

b. *Schedule 31*

Proposed Schedule 31 "Reliability Cost Adder" sets forth the fees for the provision of Reliability Coordination Service. The Reliability Cost Adder is described by Mr. Holstein in his testimony, and represents an allocated portion of the Schedule 10 costs for the reliability coordination function performed by the Midwest ISO for all tariff customers.

c. *Schedule 32*

As described above, proposed Schedule 32 sets forth the Midwest ISO's MITS charge and is described in detail by Mr. Moeller in his testimony.

d. *Attachment KK*

Proposed Attachment KK contains three *pro forma* Service Agreements that correspond to the three types of Coordination Services offered in Module F. Any non-conforming service agreements would be filed with the Commission consistent with the Commission's regulations and Order No. 2001.

e. *Attachment LL*

Proposed Attachment LL contains the Midwest ISO's newly revised standard CMP now in effect on the TVA seam, the SPP seam and the PJM seam.[48]

f. *Attachment MM*

Proposed Attachment MM contains the *pro forma* transmission service provisions that Market Coordination Customers will be required to adopt in their tariffs as a precondition to receiving service under Part III of Module F.

g. *Module C Revisions*

Certain conforming revisions to Module C are required to implement the Western Markets Proposal, including the recognition of Market Participants taking transmission service under a Market Coordination Customer's tariff as eligible to receive ARR Entitlements.

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[48] *See* Letter Order, Docket Nos. ER08-55-000 and -001 (February 4, 2008); Letter Order, Docket Nos. ER07-1417-001 (February 21, 2008).

h. Credit Policy Revisions

The Midwest ISO proposes revisions to its Credit Policy, which is set forth in Attachment L of the Tariff, to ensure that Coordination Customers are subject to appropriate credit requirements.

III. BENEFITS OF THE WESTERN MARKETS PROPOSAL

The Western Markets Proposal is expected to result in significant benefits to both existing and new Midwest ISO members. Mr. Moeller explains a number of such benefits in his testimony, including reliability benefits, improvements in congestion management procedures, and reduction in energy and administrative costs.[49]

With respect to the reliability benefits of the Western Markets Proposal, Mr. Moeller observes that closer coordination with MAPP members and a more seamless integration into the Midwest ISO Energy and Operating Reserve Markets will improve regional reliability in several ways.[50] To the extent entities choose Energy and Operating Reserve Market Coordination Service, the inclusion of the expanded footprint in the Day-Ahead Energy and Operating Reserve Market will enable the application of the SCUC within the next-day Reliability Assessment Commitment ("RAC") process to access generators that today the market cannot assess. This will ensure that there is a set of generators on line at the appropriate times to be able to manage the power system within safe parameters. Further, the Midwest ISO's SCED will significantly enhance the resolution of congestion, which in turn reduces the probability of system failure.[51] Even with respect to customers taking only Reliability Coordination Service under Part I of Module F, the Midwest ISO will enhance its ability to "see" developments in the entire Midwest region, which allows preemptive rather than reactive action. In addition, the Midwest ISO will be providing a standard form of service rather than entering into separately negotiated agreements with terms and conditions that could lead to differing interpretations by operators during an emergency. Mr. Moeller notes that there would be erosion in reliability in the region if MAPP transmission owners were to choose not to participate in services provided under Module F.

With respect to the congestion management benefits of Part III service, Mr. Moeller observes that the Western Markets Proposal will extend the efficiency benefits of LMP-based congestion management mechanisms to a broader array of customers.[52] In Order No. 2000, the Commission recognized the superiority of market-based congestion management over its non-

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[49] Moeller Testimony, at 18-22.

[50] *Id.* at 18-19.

[51] As noted *supra*, the Commission has recognized that SCED-based congestion management is a more advanced and precise instrument than TLRs.

[52] Moeller Testimony, at 19-21.

market alternatives, such as TLRs.[53] The Western Markets Proposal would replace, to a large extent, the inefficient TLR mechanisms with generation-based congestion management, which uses both the electrical effects of dispatch and the cost effects of dispatch to solve congestion in the least-cost or most efficient manner on a five-minute interval with very little manual intervention. Mr. Moeller explains that managing what was previously a market-to-non-market "seam" by using the Midwest ISO's SCUC and SCED protocols will reduce the Revenue Sufficiency Guarantee ("RSG") cost of managing congestion and will be more consistent with cost causation principles.

Another significant benefit of the Western Markets Proposal is the addition of new sources of low-cost power. Mr. Moeller explains that this will reduce energy costs for both existing and new market participants, as the most efficient mix of resources available for both energy production and ancillary services is committed and dispatched within the Energy and Operating Reserve Markets.[54] Further, the Western Markets Proposal will benefit existing customers by reducing their administrative costs due to economies of scale because the Midwest ISO's systems are scaleable and can provide service to Module F customers at a modest incremental cost. In their testimony, Mr. Moeller and Mr. Holstein further discuss certain financial benefits associated with the Western Markets proposal.[55]

IV. CONSISTENCY WITH ORDER NO. 2000

Although the Western Markets Proposal represents a novel approach towards regional and market coordination, it is consistent with the principles underlying Order No. 2000. The Commission has emphasized in Order No. 2000 the importance of sufficient scope and regional configuration for an RTO to be able to "maintain reliability, effectively perform its functions and support efficient and non-discriminatory power markets."[56] In his testimony, Mr. Edwards explains that this issue is particularly salient for the Midwest region and that the Western Markets Proposal is a bold step towards closer voluntary integration for the benefit of all customers and participants, ensuring better reliability coordination in the region.[57]

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53 Mr. Moeller explains that unlike generation-based congestion management, TLR does not investigate the least-cost alternative for congestion management, but simply continues to curtail transactions in the offending direction until the congestion is solved. Under a TLR regime, there is no process or capability to seek energy flow in a defensive direction. Since there is no economic information associated with the hourly transmission schedules used to effect curtailment, it is not possible to determine an economic optimization and it is not possible to affect flow for 30 to 60 minutes from the time that intervention for congestion management was required. *Id.* at 19-20.

54 *Id.* at 21-22.

55 *Id.* at 18-22, Holstein Testimony, at 10.

56 *Regional Transmission Organizations, Order No. 2000*, FERC Stats & Regs ¶ 31,089, at 31,079 (1999), order on reh'g, Order No. 2000-A, FERC Stats & Regs ¶ 31,092, at 31,372 (2000). See also 18 C.F.R. § 35.34(j)(2) (2007).

57 Edwards Testimony, at 5.

Under Order No. 2000, RTOs are required to "ensure the development and operation of market mechanisms to manage transmission congestion."[58] These mechanisms "must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions."[59] Mr. Edwards explains that by extending the benefits of the Midwest ISO's LMP-based congestion management system to contiguous transmission provider territories, the Midwest ISO will further enhance this important principle.[60]

Order No. 2000 also requires RTOs to address parallel path flow issues and emphasizes interregional coordination.[61] Mr. Edwards notes that the comprehensive menu of Coordination Services that the Midwest ISO offers in its Western Market Proposal goes to the heart of this requirement by replacing disparate *ad hoc* reliability arrangements with standardized tariff services open to all eligible customers.[62] In addition, the Western Markets Proposal will make efficient, market-based congestion management mechanisms available to a broader array of membership.

Mr. Edwards further explains that although a measure of pancaking would remain in the region because customers that take proposed Coordination Services would retain their own transmission tariffs and continue to be providers of transmission service on their facilities, the appropriate yardstick to measure progress in this area is to compare the Western Markets Proposal with the *status quo*.[63] Many customers that have expressed an interest in Market Coordination Service, particularly non-jurisdictional entities, would not be interested in becoming signatories to the ISO Agreement and transferring control over their facilities to the Midwest ISO, at least in the foreseeable future. As a result, rate pancaking will continue to exist in the region in any event. The Western Markets Proposal recognizes this reality while taking a substantial step towards closer integration. This is consistent with Order No. 2000, which provides that "non-participating transmission owners" are not required to de-pancake their transmission rates.[64] In addition, the Commission also made it clear that it would not deny RTO status merely because some transmission owners in the region have not transferred control over their facilities to the RTO.[65] Further, in approving the Western Markets Proposal, the Commission may properly take into account the fact that it is an improvement on the *status quo* by a successful RTO rather than a start-up proposal. While non-pancaked transmission rates may be a "central attribute of RTO formation,"[66] Mr. Edwards notes that a more flexible approach is warranted for evaluating proposals by functioning RTOs that seek to expand their

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58 18 C.F.R. § 35.34(k)(2) (2007).
59 *Id.*
60 Edwards Testimony, at 5-6.
61 *See* 18 C.F.R. §§ 35.34(k)(3) and (8) (2007).
62 Edwards Testimony, at 6.
63 *Id.* at 6-8.
64 *See, e.g., Order No. 2000*, FERC Stats & Regs ¶ 31,089, at 31,180 (2000).
65 *See Order No. 2000*, FERC Stats & Regs ¶ 31,089, at 31,086 (1999).
66 *Order No 2000-A, FERC Stats & Regs ¶ 31,092, at 31,383 (2000).*

footprints to benefit customers and market participants. Importantly, the Commission's principle of open architecture also supports the Western Markets Proposal. This principle holds that Order No. 2000 does not limit the capability of an RTO to evolve in ways that would improve its efficiency or to evolve with respect to its organizational design, market design, geographic scope, ownership arrangements or methods of operational control to the extent consistent with the foundational principles.[67]

Finally, the Commission should not fear that the availability of Module F services would unravel the Midwest ISO or some other RTO. Mr. Edwards explains that the exit fee that will apply to a withdrawing Midwest ISO Transmission Owner pursuant to the ISO Agreement will operate to discourage casual withdrawals.[68] In addition, the Commission may always limit the benefits of retaining control of transmission assets by prohibiting resumption of rate pancaking, and by reviewing any withdrawal proposals to determine whether market power or other problems would ensue. Conditions that might be imposed to remedy such problems would be another factor for any Transmission Owner weighing the decision to withdraw from the ISO Agreement to switch to service under Part III of Module F.

V. STAKEHOLDER PROCESS

In his testimony, Mr. Moeller explains that the Midwest ISO has used an open, cooperative approach to develop the Western Markets Proposal.[69] The proposal development process included numerous telephone conferences and face-to-face meetings with interested MAPP participants and other parties. The Midwest ISO posted its drafts and discussion papers on its website and sought and received input from interested parties. The Midwest ISO also discussed the proposal with its Transmission Owner constituency, which provided input to the Midwest ISO, both in oral and written form. The proposal was considered by the Advisory Committee, the Midwest ISO's highest stakeholder forum, on two occasions. On December 10, 2007, the Midwest ISO presented a draft proposal to the Advisory Committee for review and discussion. On February 20, 2008, the Advisory Committee formally considered the proposal and adopted a resolution supporting the Midwest ISO's effort. Finally, the nearly completed package of documents were reviewed by the Midwest ISO Tariff & Business Practices Workgroup at its February 22, 2008 meeting.

VI. FILING RIGHTS

Under Section II.D of Appendix K of the ISO Agreement, the Midwest ISO Transmission Owners "possess the full and exclusive right to submit filings under FPA Section 205 with regard to transmission rate design associated with rates affecting more than one zone as well as for transactions going through or out of the Midwest ISO." The Midwest ISO and the Midwest

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67 *See* 18 C.F.R. §§ 35.34(k)(8)(2) (2007).
68 Edwards Testimony, at 8-9.
69 Moeller Testimony, at 39-40.

ISO Transmission Owners agree that the Market Integration Transmission Service rates set forth in proposed Schedule 32 fall within this provision. The Midwest ISO Transmission Owners have followed the governance process required under the ISO Agreement with respect to such filings and the proposed Scheduled 32 was approved at a meeting of the Midwest ISO Transmission Owners held on February 27, 2008. The Midwest ISO Transmission Owners hereby join the Midwest ISO as a filing entity solely for purposes of proposed Schedule 32.[70]

VII. EFFECTIVE DATE

The Midwest ISO respectfully requests that the proposed EMT revisions become effective on June 1, 2008, which date is not less than sixty (60) days from the date of this filing.

VIII. SUPPORTING DOCUMENTS

This Transmittal Letter is intended to provide the Commission with an overview of the Western Markets Proposal and the corresponding Tariff changes. The attached testimony provides a more detailed discussion of the proposed Tariff design and corresponding Tariff changes. The Transmittal Letter and testimony should not, however, be relied upon to detail each and every change that is proposed by the Midwest ISO in the instant filing. The attached Tariff sheets contain all of the proposed Midwest ISO Tariff changes. The supporting documents submitted with this filing are as follows:

Attachment A	Redlined Tariff Sheets[71]
Attachment B	Clean Tariff Sheets
Attachment C	Prepared Direct Testimony of T. Graham Edwards (Ex. MISO-1)
Attachment D	Prepared Direct Testimony of Clair J. Moeller (Ex. MISO-2)
Attachment E	Prepared Direct Testimony of Michael P. Holstein (Ex. MISO-3)
Attachment F	Prepared Direct Testimony of Richard Doying (Ex. MISO-4)

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70 The Midwest ISO Transmission Owners' support for Schedule 32 does not necessarily indicate support by each individual Transmission Owner for the entire filing. The Transmission Owners reserve the right to intervene and comment on the filing.

71 Existing Tariff sheets are the only documents that reflect redlines.

IX. SERVICE AND WAIVERS

The Midwest ISO has served all parties provided in the Commission's eService list for the above-referenced docket. In addition, the Midwest ISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the EMT, Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, as well as all state commissions within the Region. In addition, the filing has been posted electronically on the Midwest ISO's website at www.midwestmarket.org under the heading "Filings to FERC" for other interested parties in this matter.

The Midwest ISO requests waiver of Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2007), to the extent applicable to this filing and requests waiver of any other applicable requirement of 18 C.F.R. Part 35 for which waiver is not specifically requested, if necessary, in order to permit Commission acceptance of this filing.

X. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

<u>For the Midwest ISO:</u>

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XI. CONCLUSION

Wherefore, for all the reasons stated above, the Midwest ISO respectfully requests that the proposed Tariff revisions be approved as set forth herein.

Very truly yours,

S. Teichler (SRS)

Stephen L. Teichler
Counsel for the Midwest Independent Transmission System Operator, Inc.

Wendy N. Reed
Counsel for the Midwest ISO Transmission Owners

SLT/srs

Attachments

cc: Jennifer Amerkhail, FERC
Susan J. Court, FERC
Patrick Clarey, FERC
Christopher Miller, FERC
Penny Murrell, FERC
Melissa Lord, FERC
Michael Donnini, FERC
John Rogers, FERC

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77.3.4 The Reliability Coordination Customer shall also be responsible for payment of an allocated share of the accrued current liabilities on the balance sheet of the Transmission Provider as of the date of termination of the Service Agreement.

77.3.5 The Reliability Coordination Customer shall pay a load ratio share of these incremental financial obligations. The load ratio share shall be calculated as the Reliability Coordination Customer's monthly peak demand for the twelve months preceding the termination of the Service Agreement, relative to the sum of the monthly peak demand during that period of all Reliability Coordination Customers and all Tariff Customers receiving Network Integration Transmission Service under the Tariff. All peak demand information shall be converted into Maximum Energy Transfer data as defined in Part II, Section A, of Schedule 10 of this Tariff. The Transmission Provider shall use the non-coincident peak demand for each Reliability Coordination Customer multiplied by the number of hours in a month to derive the Reliability Coordination Customer's Maximum Energy Transfer value. The Transmission Provider shall compute Maximum Energy Transfer values for its Tariff Customers taking Network Integration Transmission Service during the preceding month from their non-coincident peak demand. The Reliability Coordination Customer shall pay the entire amount owed under this Section 77 at the time the applicable Service Agreement is terminated.

77.3.6 As to a Reliability Coordination Customer to which Section 12E of this Tariff applies, the obligation to make the payments under this Section is subordinate and junior in all respects to the obligation of the Reliability Coordination Customer to pay the principal and interest on its bonds.

77.4 Each Reliability Coordination Customer shall provide to the Transmission Provider the monthly peak demand required by the Transmission Provider to calculate the applicable charge as set forth in Schedule 31 of this Tariff. Such data shall be transmitted electronically to the Transmission Provider no more than five (5) Business Days after the end of each calendar month.

77.5 During March of each calendar year, the Transmission Provider shall update the percentage cost allocations currently set forth in Table 1 and Table 2 of Schedule 31 of this Tariff. The revised percentage cost allocation values shall then be used to compute monthly charges for Reliability Coordination Service for the next twelve months as specified in Schedule 31. On or before April 1 of each year in which the applicable Service Agreement is in effect, the Transmission Provider shall provide to the Reliability Coordination Customer a copy of the applicable charge cost allocation for the twelve month period beginning April 1, and a reasonable explanation of its calculation.

77.6 Notwithstanding any other provision of this Part I of Module F, all amounts paid by the Transmission Provider as the result of fines or penalties imposed by or associated with a NERC or a Regional Entity enforcement action shall be recovered pursuant to a Commission-approved Tariff charge, and the Reliability Coordination Customer shall pay its allocated share of such costs, on the same basis as other costs included in the charges set forth in Section 77 of this Tariff.

78 Reliability Coordination Technical Committee

78.1 A Reliability Coordination Technical Committee is hereby established. The Transmission Provider and each Reliability Coordination Customer shall be a voting member of the Reliability Coordination Technical Committee.

78.2 The Reliability Coordination Technical Committee shall also coordinate its efforts with the Joint Coordinating Committee formed to address matters relevant to and arising under services performed under Part III of this Module F.

78.3 A member's representative in the Reliability Coordination Technical Committee shall be a person of reasonable competency and with such authority as to uphold the decisions made, to the extent such decisions do not require formal approval under governing state laws and regulations.

78.4 The Reliability Coordination Technical Committee shall meet at least quarterly during the first year after the effective date of Part I of this Module F, and shall meet periodically thereafter as the Reliability Coordination Technical Committee shall, by a majority vote of three-fourths of those entitled to vote, determine to be necessary to perform its duties in a reliable and efficient manner.

78.5 In cooperation with the Transmission Provider, and consistent with the requirements of this Tariff and all applicable reliability standards, the Reliability Coordination Technical Committee shall:

a. review procedures for the implementation of the operating and technical requirements of Part I of this Module F;

b. review and comment upon operating practices and guides to ensure the safe and reliable operation of their facilities consistent with applicable NERC and Regional Entity standards;

c. identify procedures for coordinating and integrating the operating and technical requirements of Part I of Module F with those of Part III of this Module F;

d. participate in the development of Business Practice Manuals for the administration of Part I of this Module F on a reliable and economically efficient basis; and

e. address other matters referred to in, or necessary for implementation, administration or operation of, Part I of this Module F.

78.6 Recommendations and other actions of the Reliability Coordination Technical Committee shall be by a three-fourths majority of those present and entitled to vote under the rules adopted by the Reliability Coordination Technical Committee to govern its proceedings. Nothing herein shall prohibit the Reliability Coordination Technical Committee from developing rules and procedures regarding proxy voting, and/or procedures to allow electronic meeting or voting.

78.7 All proceedings and decisions of the Reliability Coordination Technical Committee shall be reduced to writing and signed by the Reliability Coordination Technical Committee representatives, but such proceedings and decisions shall not be inconsistent with and shall not serve to contradict any terms or conditions of the Tariff in effect at the time of such procedures or decisions being made or developed.

78.8 Participation in the activities of the Reliability Coordination Technical Committee by the Transmission Provider or by the Reliability Coordination Customer shall not constitute a waiver by that entity of any of its rights under the Federal Power Act to initiate a proceeding, make any other filing, or advance any position regarding any matter before the Commission.

78.9 The Reliability Coordination Technical Committee may coordinate its activities with the activities of the Reliability Subcommittee of the Transmission Provider's stakeholder group, and may vote to suspend some or all of the meetings of this committee in order to attend and participate in the activities of the Reliability Subcommittee if the Charter of the Reliability Subcommittee provides for such participation.

II. INTERCONNECTED OPERATIONS AND CONGESTION MANAGEMENT SERVICE

Preamble

The Transmission Provider shall provide, subject to the terms and conditions of this Part II of Module F, specific congestion management services, including redispatch of generation within the Energy and Operating Reserve Markets, for interconnected transmission providers.

79 Eligibility

79.1 To be eligible for Interconnected Operations and Congestion Management Service under this Part, a Congestion Management Customer must: (i) be a NERC Registered Transmission Provider providing reciprocal transmission service pursuant to an open access transmission tariff or other applicable tariff using transmission facilities that are physically connected to the Transmission System; and (ii) register as a Market Participant pursuant to the Tariff. A Congestion Management Customer may not be, during the time service is provided under this Part II, a signatory to the ISO Agreement. As a condition to obtaining service, the Congestion Management Customer must execute an applicable Service Agreement, as set forth in Section 85 and Attachment KK-2 of this Tariff, and provide to the Transmission Provider the information required by this Part.

80 Transfer of Information and Data

80.1 The Transmission Provider and the Congestion Management Customer (or the Congestion Management Customer's tariff administrator or Reliability Coordinator as appropriate) shall transfer to each other the following types of data and information:

(a) Real-Time and Projected Operating Data (80.1.1);

(b) SCADA Data (80.1.2);

(c) EMS Models (80.1.3); and

(d) Operations Planning Data (80.1.4).

The Transmission Provider and the Congestion Management Customer shall provide to each other the data identified in items (a) through (d) above with respect to all transmission owners for which they administer transmission service on the effective date of this Part and thereafter, whether or not they administer such transmission service as of the effective date. The Transmission Provider and the Congestion Management Customer shall cooperate to supply such data and information (to the extent such information is the subject of this Part) as the Independent Market Monitor may request in order to facilitate monitoring in accordance with the Transmission Provider's Commission-approved market monitoring plan.

To ensure the accuracy of all critical operating data, the Transmission Provider and the Congestion Management Customer will designate to each other, a contact person 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, the Transmission Provider and the Congestion Management Customer shall provide to each other the name, telephone number, e-mail address, and fax number. The Transmission Provider and the Congestion Management Customer may change a designated contact from time to time by notice to each other's designated representative. The Transmission Provider and the Congestion Management Customer shall transfer data to each other in a timely manner consistent with existing defined formats or such other formats to which they may agree. If any required data transfer format has not been agreed upon as of the effective date of this Part, or if the Transmission Provider or the Congestion Management Customer determines that an agreed format should be revised, it shall give notice of the need for an agreed format or revision to the other party, and the Transmission Provider and the Congestion Management Customer will jointly seek to complete development of the format within thirty (30) days of such notice. Upon agreement, development will be completed as soon as practical.

80.1.1 The Transmission Provider and the Congestion Management Customer shall exchange two categories of operating data, real-time information and projected information, as follows:

a. The real-time operating information consisting of:

i. generation status of the units, as telemetered or as derived from the unit breaker, in each party's tariff or footprint;

ii. transmission line status, *i.e.*, status of switching devices associated with each end of the line;

iii. balancing authority area demands;

iv. selected real-time telemetered bus loads where available;

v. scheduled use of reservations;

vi. critical facility limits; and

b. Projected operating information consisting of:

i. merit order block loading;

ii. generating unit and transmission facilities maintenance schedules;

iii. the planned operational start-up or change dates for any permanently added, removed or significantly altered transmission segments; and

iv. the planned start-up testing and operational start-up or change dates for any permanently added, removed or significantly altered generation units.

80.1.2 The Transmission Provider and the Congestion Management Customer shall transfer data as set forth below, consistent with NERC requirements for the transfer of data by balancing authorities and Reliability Coordinators:

i. The Transmission Provider and the Congestion Management Customer shall transfer requested SCADA Data via ICCP or ISN;

ii. The Transmission Provider and the Congestion Management Customer shall accommodate, as soon as practical, the other party's requests for additional existing ICCP/ISN bulk transmission data points, after the request has been submitted;

iii. The Transmission Provider and the Congestion Management Customer shall respond, as soon as practical, to the other party's requests for additional, unavailable ICCP/ISN bulk transmission data points, but in any event no more than two (2) weeks after the request has been submitted, with an expected availability target date for the requested data;

iv. The Transmission Provider and the Congestion Management Customer shall comply with all governing confidentiality agreements executed between them relating to ICCP/ISN data; and

v. All ICCP data transferred between the Transmission Provider and the Congestion Management Customer shall be transferred via ISN (NERCNet), unless another transfer platform is otherwise agreed upon.

80.1.3 The Congestion Management Customer and the Transmission Provider shall exchange EMS models once a year in the common information model ("CIM") format adopted by the NERC Data Exchange Working Group, or in an otherwise agreed-upon format, with monthly updates to be provided as new data becomes available. This yearly transfer will include the ISN data definition files, identification of individual bus loads, seasonal equipment ratings and one-line drawings that will be used to expedite the model conversion process. The monthly updates represent the incremental changes that have occurred to the EMS model since the last monthly update.

80.1.4 Upon the written request of either the Transmission Provider or the Congestion Management Customer, the other party shall provide the information specified in Sections 80.1.4.1 through 80.1.4.11 of this Tariff. Each request shall specify the information sought and the frequency upon which it shall be provided, and, with respect to Sections 80.1.4.6, 80.1.4.7, and 80.1.4.8, the reason why provision of the information is necessary to achieve the objectives of Part II of this Module F.

If the Transmission Provider or the Congestion Management Customer receives a request under this Section, it shall provide the information promptly to the extent the information is available.

80.1.4.1 - Flowgates:

i. Flowgate definitions including seasonal TTC, TRM, CBM, and appropriate multipliers;

ii. Flowgates to be added to OASIS Request Evaluation processes on demand, if needed immediately for reliability;

iii. List of Coordinated and Reciprocal Coordinated Flowgates;

iv. List of Flowgates to recognize when processing transmission service (if different than list of Coordinated and Reciprocal Flowgates);

v. Operating Guides; and

vi. Requirements under Section 81.1.7 of this Tariff.

80.1.4.2 - Transmission Service Reservations:

i. Daily list of all transmission service requests, hourly increment of new requests and status changes on existing requests;

ii. List of reservations to include and to exclude; and

iii. Requirements under Sections 81.1.4 and 81.1.5 of this Tariff.

80.1.4.3 – AFC Data:

The Transmission Provider and the Congestion Management Customer currently meet and will continue to meet a minimum periodicity for calculating and posting AFCs. The minimum periodicity depends on the service being offered. The following AFC data will be provided:

i. Hourly for the first seven (7) days posted at a minimum, once per hour;

ii. Daily for days eight (8) through thirty-one (31) posted at a minimum, once per day; and

iii. Monthly for months two (2) through thirty-six (36) posted at a minimum, once per month.

80.1.4.4 - Load Forecast:

The Transmission Provider and the Congestion Management Customer will provide the following load forecast information.

i. Hourly for next seven (7) days, daily for days three (3) through thirty-one (31), and monthly for months two (2) through thirty-six (36) submitted once a day;

ii. Identify whether the load forecast is for Balancing Authority Area or sub-Balancing Authority Area (by company within the Balancing Authority Area) forecast;

iii. Indicate whether this includes transmission system losses, and if it does, indicate what the percent losses are;

iv. Identify non-conforming loads, as defined by NERC;

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

v. Requirements under Section 81.1.6. of this Tariff.

80.1.4.5 - Generator Data:

i. Unit owner, bus location in model;

ii. Seasonal ratings, PMIN, PMAX, QMIN, QMAX;

iii. Station auxiliaries to extent gross generation has been reported;

iv. Regulated bus, target voltage and actual voltage;

v. Planned maintenance; and

vi. Real-time output (MW & Mvar) with net generation after being reduced for station auxiliaries preferred.

80.1.4.6 – Jointly-Owned Units:

i. Deemed ownership shares;

ii. Treatment as pseudo tie or dynamic/static schedules;

iii. Rules for sharing output between joint owners of those units that affect the operating seam between the Transmission Provider and the Congestion Management Customer; and

iv. Transmission arrangements between joint owners.

80.1.4.7 - Intermittent Generation:

i. Accredited capacity;

ii. Planned maintenance;

iii. Whether aggregated generation or generation by piece of equipment;

iv. Whether all output is tagged; and

80.1.4.8 - Balancing Authority Area Net Interchange from Reservations and Tags:

i. Any grandfathered agreements that do not appear in OASIS; and

ii. If tags and reservations can no longer be used to develop balancing authority area or zone net interchange, merit order block loading information will be needed for all generators in the balancing authority area/zone.

80.1.4.9 - Dynamic Transfers:

i. List of dynamic transfers;

ii. Identification of each dynamic transfer as a dynamic schedule or pseudo-tie, as defined by NERC; and

iii. Requirements under Section 81.1 of this Tariff.

80.1.4.10 - Controllable Devices:

i. List of controllable devices that may include: phase shifters, DC lines, and back-to-back AC/DC converters; and

ii. Operating practices of the controllable devices.

80.1.4.11 - Generation and Transmission Outages:

i. Generation Outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 81.1.1 of this Tariff;

ii. Transmission Outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 81.1.3 of this Tariff; and

iii. Prompt notification of all forced Outages of both generation and transmission resources.

80.2 The Transmission Provider and the Congestion Management Customer shall periodically confer regarding the need to transfer any information other than that identified for transfer in Section 80.1, and shall negotiate in good faith to make agreements for the transfer of such additional information as is necessary to achieve the objectives of this Part.

80.3 The Transmission Provider and the Congestion Management Customer shall bear their own cost of providing information to each other pursuant to Sections 80.1 and 80.2 of this Tariff.

81 TTC/ATC/AFC Protocols

81.1 As of the effective date of this Part, the Transmission Provider and the Congestion Management Customer shall use the NERC System Data Exchange ("SDX") System to transfer the status of generators, Outages of all interconnections and other critical transmission facilities, and peak load forecasts, which has the capability to house daily data for the next seven (7) days, weekly data for the next month, and monthly data for the next year. The specific criteria for satisfying the requirements of this Section 81 shall be set forth in the TTC/ATC/AFC Protocol which shall be incorporated into and made a part of the Service Agreement executed by the Congestion Management Customer and the Transmission Provider pursuant to Section 85 and Attachment KK-2 of this Tariff.

81.1.1 The Transmission Provider and the Congestion Management Customer shall provide each other with projected status of generation availability over the next twelve (12) months. If information is available, the Transmission Provider and the Congestion Management Customer may provide more than twelve (12) months of information regarding the projected status of generation availability. The Transmission Provider and the Congestion Management Customer 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 generator availability data, such that each party is aware of the "return date" of each generator subject to a scheduled or forced outage.

81.1.2 As necessary to permit the Transmission Provider and the Congestion Management Customer to develop a reasonably accurate dispatch for the calculation of TTC and ATC/AFC values under any modeled condition, they shall provide each other with a typical generation merit order or the generation participation factors of all units on an affected balancing authority area basis. The generation merit order will be updated as required by changes in the status of the unit; however, a new generation merit order need not be provided more often than prior to each peak load season.

81.1.3 The Transmission Provider and the Congestion Management Customer shall provide each other with the projected status of transmission outage schedules over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the "outage date" and "return date" of a transmission facility from a scheduled or forced outage.

81.1.4 The Transmission Provider and the Congestion Management Customer shall make available to each other their interchange schedules, as required to permit accurate calculation of TTC and ATC/AFC values. Due to the high volume of this data, the Transmission Provider and the Congestion Management Customer shall either post this data to an FTP site for download or shall request NERC to modify the IDC to allow for selected interrogation by each other.

81.1.5 The Transmission Provider and the Congestion Management Customer shall coordinate transmission service requests as follows:

81.1.5.1 The Transmission Provider and the Congestion Management Customer shall make available to each other, on an FTP site, all transmission service request information available for integration into their ATC/AFC calculation process. The Transmission Provider shall provide transmission service request information from its OASIS Node. The Congestion Management Customer shall provide transmission service request information from the Congestion Management Customer OASIS Node.

81.1.5.2 The Transmission Provider and the Congestion Management Customer shall develop practices for modeling their transmission service requests, including external third party requests. The Transmission Provider and the Congestion Management Customer shall provide each other with the procedures developed and implemented to model intra-party requests under the Congestion Management Customer's transmission tariff and other designated tariffs that may be used to provide transmission service.

81.1.5.3 Transactions are not included in ATC/AFC determinations if the impacts from the transmission service request are already accounted in a base case model or some other component of the ATC/AFC calculation. The Transmission Provider and the Congestion Management Customer shall create and maintain a list, on an FTP site, of transmission service requests on their OASIS Node that are not included in their own ATC/AFC determination process, so that the transmission service request is excluded in each other's analysis.

81.1.6 The Transmission Provider and the Congestion Management Customer shall transfer peak load data for each period (e.g., daily, weekly, and monthly). Because peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next seven (7) day horizon, the Transmission Provider and the Congestion Management Customer shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile.

81.1.7 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 to assure that the Transmission Provider and the Congestion Management Customer respect each other's Flowgates, the Transmission Provider and the Congestion Management Customer will transfer Firm and Non-firm AFC for all Coordinated Flowgates. The Transmission Provider and the Congestion Management Customer will continue to accept or reject transmission service requests based upon projected loadings on their own Flowgates as well as the loadings on the other party's Flowgates so as not to exceed the posted AFC.

81.1.8 The Transmission Provider and the Congestion Management Customer will transfer (seasonal, normal and emergency) Flowgate Ratings as well as all limiting conditions (thermal, voltage, or stability). The Transmission Provider and the Congestion Management Customer will update this information in a timely manner as required by changes on the transmission system.

81.1.9 In accordance with Attachment LL of this Tariff, Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating party's model to the extent inclusion is practical. The Transmission Provider and the Congestion Management Customer shall use the response factor cut-off that the owning/operating party uses for its Flowgate in its AFC determination efforts.

81.1.10 The Transmission Provider and the Congestion Management Customer will ensure that all significant system changes are incorporated in their TTC/ATC/AFC calculation models. Although this information and additional, detailed data are included in the MMWG cases, this data transfer mechanism will address the major changes that should be included in the TTC/ATC/AFC calculation models in a more timely manner. This data transfer will occur no less often than prior to each peak load season. In addition, the Transmission Provider and the Congestion Management Customer agree to transfer TTC/ATC/AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this transfer.

81.1.11 Following standardization of TTC/ATC/AFC calculations pursuant to Commission order and action by NERC and NAESB, the Transmission Provider and the Congestion Management Customer shall confer to determine whether the protocols continue to be necessary, and if so, what revisions to the protocols or this Part may be required to comply with the current standards and practices. The Transmission Provider and the Congestion Management Customer shall cooperate in good faith to implement such revisions as quickly as possible.

82 Reciprocal Coordination of Flowgates

82.1 In order to coordinate congestion management proactively, the Transmission Provider and the Congestion Management Customer agree to respect each other's determinations of AFC/ATC and curtailment priorities for real-time operations applicable to their Coordinated Flowgates (CFs). Additionally, the Transmission Provider and the Congestion Management Customer agree to respect the allocations defined by the reciprocal allocation process set forth in the Congestion Management Process (CMP), which is set forth in Attachment LL to this Tariff.

82.2 The process and timing for exchanging ATC/AFC calculations and Firm Flow calculations/allocations with respect to all RCFs are set forth in the CMP.

82.3 The Transmission Provider's and the Congestion Management Customer's capabilities and real time actions shall be governed by and in accordance with the coordination process for RCFs, as set forth in the CMP.

82.4 The Transmission Provider will utilize its Unit Dispatch System (UDS) and Security-Constrained Unit Commitment (SCUC) in effect at the time to manage the portion of the flows on an RCF allocated to the Transmission Provider. The Congestion Management Customer's Reliability Coordinator will utilize NERC TLR process to manage the portion of the flows on an RCF allocated to the Congestion Management Customer.

82.5 To the extent that the Congestion Management Customer is an owner of rights to transmission capacity on facilities comprising the North Dakota Export flowgate ("NDEX"), and one or more other owners of such rights are either Transmission Owners or Market Coordination Customers under this Tariff, the Transmission Provider and the Congestion Management Customer will manage congestion on the NDEX flowgate consistent with existing agreements among the owners of such rights rather than as an RCF under Attachment LL of this Tariff.

83 Generation Redispatch and Compensation

83.1 The Congestion Management Customer's Reliability Coordinator will use the NERC TLR procedures to mitigate congestion on the Congestion Management Customer's Transmission System. As a condition of service under this Part, the Congestion Management Customer shall redispatch generation under its control, as set forth in Section 83.2 through Section 83.6 of this Tariff, for the purpose of relieving actual or contingency overloads on Designated Flowgates.

83.2 Upon each other's request, the Transmission Provider and the Congestion Management Customer shall confer to identify: (i) transmission operating constraints that could result in TLR or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation controlled by the Congestion Management Customer, and (ii) the generation units on the Congestion Management Customer's system, the redispatch of which would alleviate the identified transmission constraints. In the event that the Transmission Provider and the Congestion Management Customer identify such additional transmission constraints and generation units, the applicable Service Agreement may be amended to include such additional transmission constraints and generating units. Agreement to such additional transmission operating constraints or generation units shall not be unreasonably withheld.

83.3 The following redispatch procedures shall apply to generation redispatch arising under this Part II:

83.3.1 Redispatch procedures (operation procedures) for each flowgate shall be developed and agreed upon in writing by the Transmission Provider and the Congestion Management Customer prior to providing redispatch service. Implementation of the operating procedures shall be coordinated with the Congestion Management Customer.

83.3.2 If TLR is called on a transmission flowgate subject to this Part, then the Transmission Provider may request that the Congestion Management Customer redispatch one or more of the units identified in the applicable Service Agreement or pursuant to Section 83.2 hereof to alleviate the Transmission Provider's TLR assigned impacts on the transmission flowgate.

83.3.3 Upon such request, the Congestion Management Customer will redispatch, under the direction of the Transmission Provider, one or more of the units identified in the applicable Service Agreement or pursuant to Section 83.2. In no event shall the Congestion Management Customer be required to redispatch or cycle the output of any unit if such redispatch or cycling: (i) may impair the safe and reliable operation of the Congestion Management Customer units; (ii) is inconsistent with Good Utility Practice; or (iii) is contrary to any NERC requirement, or any legal or regulatory rule, standard or prohibition.

83.3.4 The Congestion Management Customer will not implement a redispatch request under this Section 83.3, unless and until the Transmission Provider verifies the availability and deliverability into the Congestion Management Customer's system of replacement power from the Energy and Operating Reserve Markets, if such power is required by the Congestion Management Customer. If the Transmission Provider and the Congestion Management Customer do not concur on the availability and deliverability of replacement power, and that the purchase of such power as described in Section 83.4 of this Tariff can be completed without creating adverse conditions elsewhere on the systems of either party, the Congestion Management Customer will not implement the redispatch request.

83.3.5 If initiating a redispatch request involves a time commitment for the Congestion Management Customer's generators such as minimum run times, minimum down times and/or a fuel delivery commitment period, this will be provided in the response to the request for redispatch and will be factored into the decision to proceed with the redispatch request.

83.3.6 If there is mutual agreement between the Transmission Provider and the Congestion Management Customer to implement a redispatch request, it will be implemented at a start time that may differ from the beginning of the hour. Likewise, the Transmission Provider and the Congestion Management Customer each retain the right to discontinue a redispatch request in the event the redispatch is no longer needed or the generators being used for redispatch are needed for other purposes. The redispatch will be discontinued at a mutually agreed upon stop time which may differ from the end of the hour.

83.3.7 The Transmission Provider and the Congestion Management Customer shall operate their systems in good faith and, consistent with Good Utility Practice, to avoid dispatching generation or taking other actions for the sole purpose of causing or increasing congestion on flowgates that are subject to this Part II of Module F.

83.4 The Congestion Management Customer and the Transmission Provider shall be compensated as follows for redispatch service.

83.4.1 During the period of time that the Congestion Management Customer reduces the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3, and does not simultaneously increase the output of one or more Congestion Management Customer units on the opposite side of the constraint to equal or exceed the decrease in output of the decremented units, the Congestion Management Customer shall purchase from the Midwest ISO Real-Time Energy and Operating Reserve Market at the Congestion Management Customer-Transmission Provider interface, a quantity of energy equal to the megawatt hour quantity of the net reduction in output for the duration of the net reduction in output. The price for such purchase shall be the Locational Marginal Price in effect over such time at the Congestion Management Customer-Transmission Provider interface node. The Transmission Provider and the Congestion Management Customer shall develop an Operating Procedure for the implementation of redispatch requests under this Agreement. If the Operating Procedure is followed for a redispatch request, the Congestion Management Customer shall not be required to pay any Revenue Sufficiency Guarantee charges that would otherwise be associated with purchases under this Section 83.4.1 to comply with that redispatch request.

83.4.2 For each occasion that the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3, and does not simultaneously decrease the output of one or more Congestion Management Customer units on the opposite side of the constraint to match at least the increased output of the incremented units, the Transmission Provider shall arrange, for and on behalf of the Midwest ISO Market Participants, the delivery of a quantity of energy from the Congestion Management Customer equal to the megawatt hour quantity of the net increase in output for the duration of the net increase in output. The price for such delivery shall be the LMP at the Congestion Management Customer-Transmission Provider interface node at the time of each occasion. If the Operating Procedure referred to in the preceding Section 83.4.1 is followed for a redispatch request, the Congestion Management Customer shall not be required to pay any Revenue Sufficiency Guarantee charges that would otherwise be associated with purchases under this Section 83.4.2 to comply with that redispatch request.

83.4.3 For each occasion that the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3 of this Tariff, and simultaneously decreases the output of one or more Congestion Management Customer units on the opposite side of the constraint to match the increased output of the incremented units, no purchase from the Real-Time Energy and Operating Reserve Market is required.

83.4.4 In addition, the Transmission Provider shall be obligated to pay and shall pay to the Congestion Management Customer, by and on behalf of the Midwest ISO Market Participants, in accordance with the following:

83.4.4.1 When the Congestion Management Customer decreases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3 of this Tariff and there is not an offsetting and equal increase in the output of Congestion Management Customer units on the opposite side of the constraint as described in Section 83.4.1, the Transmission Provider shall pay to the Congestion Management Customer an amount equal to the amount that the Congestion Management Customer pays to the Transmission Provider for the energy purchases described in Section 83.4.1 of this Tariff, plus any transmission and transmission related charges billed to the Congestion Management Customer to effect the redispatch request (including an adjustment to reflect increased Transmission Provider energy market resettlement charges totaling $200.00 or more in any month, related to previous redispatch events), minus the "Change in Total System Cost".

If the amount the Congestion Management Customer pays to the Transmission Provider for energy purchases described in Section 83.4.1 of this Tariff is less than the "Change in Total System Cost," there will be no Transmission Provider payment to the Congestion Management Customer.

83.4.4.2 When the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3 of this Tariff and there is not an offsetting and equal decrease in the output of Congestion Management Customer units on the opposite side of the constraint as described in Section 83.4.2, the Transmission Provider shall pay to Congestion Management Customer an amount equal to 110% of the "Change in Total System Cost," plus the Congestion Management Customer's applicable start-up costs and the cost for minimum generation output, plus any transmission and transmission related charges billed to the Congestion Management Customer to effect the redispatch request (including an adjustment to reflect increased Transmission Provider energy market resettlement charges totaling $200.00 or more in any month, related to previous redispatch events), minus the amount the Transmission Provider pays to the Congestion Management Customer for energy deliveries arranged for and on behalf of the Midwest ISO Market Participants, as described in Section 83.4.2. If 110% of the "Change in Total System Cost" is less than the amount the Transmission Provider pays to the Congestion Management Customer for energy deliveries arranged for and on behalf of the Midwest ISO Market Participants as described in Section 83.4.2, the Transmission Provider will pay the Congestion Management Customer only for its applicable start-up costs and cost for minimum generation output.

83.4.4.3 When the Congestion Management Customer increases the output of its units in response to a request from the Transmission Provider in accordance with Section 83.3 of this Tariff and there is an offsetting and equal decrease in the output of Congestion Management Customer units on the opposite side of the constraint as described in Section 83.4.3, the Transmission Provider shall pay 110% of the Congestion Management Customer's "Change in Total System Cost" plus any applicable start-up costs and the cost for minimum generation output.

83.5 In addition to the redispatch procedures set forth in this section for the redispatch of the Congestion Management Customer's generation, the Congestion Management Customer may request a shadow price that represents an estimate of the redispatch cost of the Transmission Provider's generating resources to mitigate the Congestion Management Customer's assigned TLR requirements. If the Congestion Management Customer requests the Transmission Provider to perform a Manual Redispatch of the Transmission Provider's resources, the Congestion Management Customer shall pay the Transmission Provider for and on behalf of the Midwest ISO Market Participants in an amount equal the Manual Redispatch Energy volume multiplied by such shadow price.

83.6 The amounts paid by the Transmission Provider to the Congestion Management Customer for redispatch during any hour under this Part will be funded from congestion charges collected as part of the real-time settlement. To the extent that congestion charges collected as part of the real-time settlement are not sufficient to fund the payment to the Congestion Management Customer, the remaining payment shall be funded *pro rata* by Market Participants on a load ratio share basis, where load ratio share is equal to the sum of: (i) withdrawals at Commercial Nodes, excluding withdrawals associated with Carved-Out GFAs and (ii) Exports. The amounts paid to the Transmission Provider from the Congestion Management Customer for redispatch during any hour under this Part will be added to the congestion charges collected as part of the real-time settlement and distributed to Market Participants on a load ratio share basis, where load ratio share is equal to the sum of: (i) withdrawals at Commercial Nodes, excluding withdrawals associated with Carved-Out GFAs and (ii) Exports.

83.7 The billing and payment terms for this Part shall be as set forth in Section 7.20 of this Tariff.

83.7.1 When applicable, the Transmission Provider shall pay the Congestion Management Customer all sums due for each redispatch request, determined in accordance with Section 83.3 and Section 83.4 above. Within twelve (12) calendar days of each redispatch event, the Congestion Management Customer shall provide an invoice showing the hours, and the costs incurred by Congestion Management Customer during each hour, and any other costs (including the Transmission Provider's energy market and transmission charges described in Sections 83.4.4.1 and 83.4.4.2) to comply with a redispatch request under this Part. Failure to provide the invoice within the twelve day period will not excuse, but may delay, payments due to the Congestion Management Customer until the next scheduled settlement period.

Purchases of energy by the Congestion Management Customer from the Transmission Provider under Section 83.4.1 of this Part and Market Participant charges normally billed to the Congestion Management Customer, will be netted against sums owing to the Congestion Management Customer for redispatch service under this Part. The Transmission Provider will invoice or pay the Congestion Management Customer the net amount owed or credited for all energy purchases and other Congestion Management Customer Market Participant charges, pursuant to the terms and conditions of Section 7.20 of this Tariff.

83.7.2 All net settlements owing to the Congestion Management Customer shall be due and payable by the Transmission Provider pursuant to the terms and conditions of the Tariff, whether or not a Party disputes all or any portion of the amount owing to the Congestion Management Customer for redispatch service under this Part. Payment or acceptance of disputed amounts shall not be a waiver of a party's right to challenge the correctness of that amount, or to pursue dispute resolution process of the Tariff including Commission review of the correctness of such amounts. Net settlements owing to the Transmission Provider shall be due and payable pursuant to the terms and conditions of Section 7.20 of this Tariff.

83.7.3 As to a Congestion Management Customer to which Section 12E of this Tariff is applicable, the obligation to make the payments under this Section is subordinate and junior in all respects to the obligation of the Congestion Management Customer to pay the principal and interest on its bonds.

84 Coordinated Operations and Planning

84.1 The Transmission Provider and the Congestion Management Customer acknowledge that voltage control and reactive power coordination are essential to maintain reliability. Therefore, the Transmission Provider and the Congestion Management Customer shall establish procedures ("Voltage and Reactive Power Coordination Procedures") by which their respective Reliability Coordinators shall conduct such coordination.

84.2 The Transmission Provider and the Congestion Management Customer will perform regional transmission and generation outage coordination in order to identify proposed transmission and generation maintenance that would create unacceptable reliability-related system conditions and will work with the facility owners to provide remedial steps to be taken in advance of such proposed maintenance.

84.3 The objectives of the planning coordination process are to make certain that appropriate and adequate reviews of transmission planning functions are performed between the Transmission Provider and the Congestion Management Customer on a collaborative basis to ensure comparability, efficiency and timeliness. The Transmission Provider and the Congestion Management Customer shall coordinate their planning processes by exchanging planning information required under this Part, and through joint cooperation between their respective Planning Authorities.

84.4 The Transmission Provider and the Congestion Management Customer shall make transmission capacity available within their transmission systems for generation reserve sharing. Subject to any applicable Commission rules, regulations or orders, the Transmission Provider and the Congestion Management Customer shall reserve the required TRM, or its equivalent, for its generation reserve sharing pool requirements. The party responsible for making transmission capacity available for the reserve sharing obligation shall bear the costs of any redispatch required to make the transmission capacity available.

85 Service Agreement

85.1 The Transmission Provider shall offer a standard form Service Agreement for Interconnected Operations and Congestion Management Services to the entity eligible to receive the Interconnected Operations and Congestion Management Service. Executed Service Agreements that contain the information required under this Part shall be filed with the Commission in compliance with applicable Commission regulations. The standard form of Service Agreement for Interconnected Operations and Congestion Management Services is provided in Attachment KK-2 to this Tariff.

85.2 The Transmission Provider and the Congestion Management Customer shall cooperate in good faith in making any filings before the Commission that may be required to implement the terms of this Part or any applicable Service Agreement or to facilitate their effective dates. Whenever practicable, such filings shall be made simultaneously with each other.

86 Records

86.1 The Transmission Provider and the Congestion Management Customer shall keep complete and accurate records relating to the performance of their respective obligations, as well as any calculations necessary in the performance of such obligations, under this Part and shall maintain such data as may be necessary for the purpose of ascertaining that their performance, or calculations in support of such performance, conforms to the standards set forth in this Part, including, but not limited to, data supporting the calculation of TTC, TRM, ATC/AFC, and RCF allocations.

86.2 The Transmission Provider and the Congestion Management Customer shall maintain the complete and accurate records required by Section 86.1 for a period of one year from the end of the fiscal year during which the obligations were performed. Within that one year period, either the Transmission Provider or the Congestion Management Customer may request in writing copies of the records of the other party to the extent reasonably necessary to verify that the performance, or calculations in support of such performance, conforms to this Part. The costs of the data review, including costs related to retrieving, compiling, reproducing and analyzing any data requested pursuant to this provision shall be borne by the party making the request.

86.3 Any access to the Transmission Provider's books and records shall be subject to applicable confidentiality and CEII requirements and procedures, as may be provided in the Tariff or Commission rules, regulations or orders.

87 Revenue Distribution.

87.1 Nothing in this Part II shall be interpreted to modify any prior agreement between the Transmission Provider and the Transmission Owners regarding revenue distribution.

87.2 For any charges not invoiced pursuant to Section 83.7 of this Tariff, the Congestion Management Customer shall render invoices to the Transmission Provider for amounts due in accordance with the Congestion Management Customer Customer's customary billing practices and payment shall be due in accordance with the Congestion Management Customer Customer's customary payment requirements. All payments shall be made in immediately available funds payable to the Congestion Management Customer by wire transfer pursuant to instructions set out by the Transmission Provider and the Congestion Management Customer 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).

88 Effective Date and Term

88.1 The initial term of the Interconnected Operations and Congestion Management Service shall be for a period of three (3) years after the effective date of the Service Agreement executed pursuant to Section 85 and Attachment KK-2 of this Tariff. The Service Agreement shall automatically renew thereafter for successive one (1) year terms unless written notice of termination is provided not less than one year prior to the end of the initial or any subsequent term. The Service Agreement shall also terminate and cease to be effective upon the mutual agreement by the parties to terminate the Service Agreement or upon Commission order terminating the Service Agreement. The effective date of the Service Agreement shall be the date set forth therein or any other date as may be established by the Commission.

88.2 A Congestion Management Customer to which Section 12E of this Tariff applies may terminate its Service Agreement executed pursuant to Section 85 and Attachment KK-2 of this Tariff at any time during the initial term or any extension thereof with less than the required one-year notice, in the event that the statutes governing such Congestion Management Customer, or any provisions of this Part II of Module F, or the provisions of the Transmission Provider's Tariff incorporated by reference in this Part II Module F, are changed or modified, in a manner that causes a conflict with state law, regulations, or rate schedules and the review process described in Section 12E of this Tariff is unable to resolve such conflict.

88.3 Upon written notice to the Transmission Provider that Congestion Management Customer is exercising its right to terminate its Service Agreement under Section 88.2 of this Tariff, the Transmission Provider and the Congestion Management Customer will work in good faith to make all required arrangements to resume as soon as possible, but not to exceed thirty (30) days from such written notice, all normal operating conditions and provide transmission service on their respective systems without regard to the requirements of this Part II.

III. MARKET COORDINATION SERVICE

Preamble

The Transmission Provider will provide Market Coordination Service to integrate into the Energy and Operating Reserve Markets the resources and loads interconnected to transmission facilities that are not included in the Transmission System, as set forth in this Part.

89 Eligibility

89.1 Market Coordination Customers eligible for service under this Part III must be transmission providers providing transmission service on facilities that are: (i) interconnected with the facilities of a Transmission Owner; (ii) interconnected with the facilities of another Market Coordination Customer taking service pursuant to this Part III; or (iii) interconnected with the facilities of a Congestion Management Customer taking service under Part II of this Module F that offers transmission service pursuant to terms and conditions that are consistent with or superior to the terms and conditions set forth in Attachment MM of this Tariff.

89.2 A Market Coordination Customer taking service under this Part III must also take the Reliability Coordination Service under Part I of Module F of this Tariff.

89.3 A Transmission Owner shall not be eligible for service under this Part III until it has withdrawn from the ISO Agreement pursuant to Commission approval, if applicable, and has paid its withdrawal obligation under the ISO Agreement. Nothing in this Part III of Module F shall be interpreted as an alteration of, or a limitation on, or to otherwise affect, the right of the Transmission Provider or the right of a Transmission Owner to make filings pursuant to Sections 205 and 206 of the Federal Power Act.

90 Nature of Market Coordination Service

90.1 Market Coordination Customer Facilities

90.1.1 The Transmission Provider shall not provide any transmission service on Market Coordination Customer Transmission Facilities. All forms of transmission service on Market Coordination Customer Transmission Facilities shall be provided by the Market Coordination Customer pursuant to its tariff consistent with the specific terms of this Part III of Module F and the Market Coordination Customer's obligations thereunder.

90.1.2 The Market Coordination Customer shall determine, and provide to the Transmission Provider, a list of the facilities to be included as its Market Coordination Customer Transmission Facilities, which shall be facilities used for the transmission of electric energy in interstate commerce, and facilities for which the Transmission Provider has responsibility for Reliability Coordination Service under Part I of Module F of this Tariff.

90.1.3 On an annual basis, the Market Coordination Customer shall review the determination of facilities to be included as Market Coordination Customer Transmission Facilities in Section 90.1.2, and shall notify the Transmission Provider of any facilities to be added to or removed from the list of Market Coordination Customer Transmission Facilities.

90.2 Market Coordination Service

The Transmission Provider will provide the following Market Coordination Service on the terms and conditions set forth in this Tariff:

90.2.1 The Transmission Provider will integrate the resources and loads in the Customer Zone with the Energy and Operating Reserve Markets by including the Market Coordination Customer Transmission Facilities and loads and resources in the Customer Zone in the Network Model and the Commercial Model. All resources and loads in the Customer Zone must be registered to participate in the Energy and Operating Reserve Markets, including resources and loads in or outside the Customer Zone that are Pseudo Tied into the Midwest ISO Balancing Authority Area, but excluding loads and resources in the Customer Zone that are Pseudo Tied out of the Midwest ISO Balancing Authority Area, and each of such registered resources and loads must be represented by a Market Participant.

90.2.2 The Transmission Provider will manage transmission congestion in the Transmission Provider Region using Security Constrained Economic Dispatch that includes redispatching Generation Resources, as set forth in Module C of this Tariff.

If a Market Coordination Customer holds rights, other than transmission tariff service entitlements, to transmission capacity across the North Dakota Export flowgate ("NDEX"), as established and documented through FERC-filed documents, or through existing contracts, operating agreements, and operating guides that are specified in the Service Agreement executed by the Transmission Provider and the Market Coordination Customer pursuant to Section 96 of the Tariff, the Transmission Provider will implement SCED on the NDEX flowgate consistent with existing agreements among the holders of such rights, rather than as an RCF under Attachment LL. The Market Coordination Customer shall designate in its Service Agreement KK-3, and from time to time update as required, the NDEX capacity available for use by the Transmission Provider for the dispatch of the loads and resources in its Customer Zone. The Market Coordination Customer shall make available on a non-discriminatory basis to its transmission customers, to other Market Coordination Customers, and to Transmission Customers of the Transmission Provider, any remaining rights it may hold across the NDEX flowgate in excess of the agreed-upon use set forth in the Attachment KK-3 Service Agreement. In addition, the Transmission Provider and each Market Coordination Customer will honor each other's rights when evaluating requests for long term transmission service under their respective tariffs.

90.2.3 Market Participants that are customers under the Market Coordination Customer's tariff are eligible to receive ARR Entitlements on the terms and conditions established in this Tariff, provided that: (1) they are taking network integration transmission service and/or firm point-to-point service that is comparable to Network Integration Transmission Service and/or Firm Point-to-Point Transmission Service under Module B of the Tariff; (2) they have entered into a long-term agreement for firm transmission service on the Market Coordination Customer's transmission system; (3) they timely submit the necessary information to the Transmission Provider; and (4) they timely meet the other applicable requirements of the Tariff and Business Practices Manuals. Subject to compliance with the foregoing conditions, if the transmission planning and expansion process of the Market Coordination Customer's tariff contains a provision for customer participation in the transmission planning process and also includes a transmission expansion process that demonstrates a mutual obligation to the Market Coordination Customer and the Transmission Provider to maintain simultaneous feasibility across the Combined Systems by expanding their respective transmission systems to serve Network Load, then beginning the first full allocation year of the Market Coordination Customer's participation in the Energy and Operating Reserve Markets, and in every full allocation year of its participation thereafter, customers under the

Market Coordination Customer's tariff shall also be eligible to participate in Stage 1A of the Annual ARR Allocation process. When a Market Coordination Customer first participates in the Energy and Operating Reserve Market during, rather than from the start of, an allocation year its customers shall be eligible to participate in a partial-year allocation of FTRs for the remainder of such allocation year. During the Annual ARR Registration, the customers of the Market Coordination Customer must register their existing rights by providing information requested by the Transmission Provider. A Market Participant serving bundled retail load in the Customer Zone of a Market Coordination Customer pursuant to a state approved retail electric tariff that imposes an obligation to serve under state law shall be deemed to have satisfied the requirements for eligibility to receive ARR Entitlements under this Section 90.2.3.

90.2.4 To enable the integration of resources and loads into the dispatch of the Energy and Operating Reserves Markets, the following requirements shall apply to preexisting agreements to which a Market Coordination Customer taking service under this Part is a party if such preexisting agreements apply to loads or resources that are or will be registered to participate in the Energy and Operating Reserves Markets:

90.2.4.1 As a precondition for receiving service under this Part III, a Market Coordination Customer that is a party to a Carved-Out GFA listed in Attachment P of the Tariff, to which the only other parties are another Market Coordination Customer or a Transmission Owner, will be required, for the period of time during which the Market Coordination Customer takes service under Part III of Module F, to convert such Carved-Out GFA to Option A or Option C treatment, in accordance with the requirements of Module C of the Tariff, or permanently convert such Carved-Out GFA to service under the terms of this Tariff and/or its tariff. Any Market Coordination Customer that is a party to an Option B GFA with a Transmission Owner, as listed in Attachment P of this Tariff, shall be eligible to receive service under this Part III.

90.2.4.2 As a precondition for receiving service under this Part III, a Market Coordination Customer shall provide to the Transmission Provider detailed information about every agreement that obligates the Market Coordination Customer to provide transmission service on Market Coordination Customer Transmission Facilities (including as a component of "bundled" service) to the extent such an agreement is not included in Attachment P of this Tariff. The information that the Market Coordination Customer is required to provide under this Section 90.2.4.2 shall be in the template adopted by the Commission in the Transmission Provider's GFA proceeding in Docket No. ER04-691. The Transmission Provider shall inform the Market Coordination Customer within sixty (60) days after receiving the information required whether the agreement has been correctly identified by the Market Coordination Customer. The Market Coordination Customer shall have the right to appeal the Transmission Provider's determination made under this Section 90.2.4.2 directly to the Commission under Section 206 of the Federal Power Act.

90.2.4.3 The Market Coordination Customer and the affected parties to each preexisting agreement identified in Section 90.2.4.2 shall select the appropriate treatment to be accorded each such agreement under the Tariff:

(i) preexisting agreements subject to a just and reasonable standard of review may choose:

a. Option A or Option C treatment under the Tariff; or
b. Full conversion to transmission service under the Tariff and/or the open access transmission tariff of the Market Coordination Customer.

(ii) preexisting agreements shall be identified as Carved-Out GFAs under Section 38.8.4 of the Tariff, to the extent that:

a. They are subject to the public interest standard of review;
b. They are silent on the applicable standard of review; or
c. They provide for transmission service by an entity that is not a public utility.

90.2.4.4 Parties to preexisting agreements identified in Section 90.2.4.3 (ii) may voluntarily choose Option A or Option C treatment under the Tariff, or fully convert to transmission service under the Tariff and/or open access transmission tariff of the Market Coordination Customer. Parties that convert to transmission service under an applicable tariff or this Tariff cannot revert to carved-out status.

90.2.4.5 If the parties to a preexisting agreement otherwise eligible for Carved-Out GFA treatment under Section 90.2.4.3 (ii)do not voluntarily select Option A or Options C treatment, or conversion to service under the Tariff and/or under the Market Coordination Customer's tariff, then, subject to the Balancing Authority requirements imposed by Section 90.2.5.3, each such preexisting agreement shall be treated as a Carved-Out GFA, provided, that, notwithstanding any other provision of the Tariff, in case of any insufficiency of the revenue needed to cover the Costs of Congestion relating to such preexisting agreements, the revenue shortfall shall be funded through assessments on all load in the relevant Customer Zone that is not served under a preexisting agreement subject to this Section 90.2.4.5.

90.2.5 The following balancing authority requirements shall apply to Market Coordination Customers:

90.2.5.1 If the Market Coordination Customer is a balancing authority, prior to obtaining service under this Part, the Market Coordination Customer shall sign the Balancing Authority Agreement, and shall be bound by the terms and conditions of that agreement for the term of the applicable Service Agreement and any renewal term thereof, in order to permit the Transmission Provider to perform those Balancing Authority functions required to safely and reliably operate and administer the Energy and Operating Reserve Markets in the Market Coordination Customer's Balancing Authority Area.

90.2.5.2 If the Market Coordination Customer is not a balancing authority, and the balancing authority from whom the Market Coordination Customer receives balancing authority services is not a Transmission Owner or a Market Coordination Customer receiving services under this Part, the Market Coordination Customer shall take such measures, and install such metering and other equipment, to allow the Transmission Provider to perform all necessary balancing authority functions for the Market Coordination Customer.

90.2.5.3 The Market Coordination Customer shall amend, or exercise its rights under its transmission tariff or other applicable agreements to require that for the period of time during which the Market Coordination Customer is taking service under this Part III: (i) its transmission customers with load or resources in its Customer Zone or located in its Balancing Authority Area, or in its Balancing Authority Area, shall apply to the Transmission Provider to become Market Participants and submit to the Transmission Provider information it requires to register their loads and resources as required by this Tariff, or (ii) that such transmission customers either become balancing authorities or make other arrangements for the provision of such services by a NERC certified Balancing Authority.

90.2.5.4 To the extent required by NERC or Regional Entity standards, the Transmission Provider will enter into such emergency assistance or similar agreements with balancing authorities that adjoin the Market Coordination Customer Transmission Facilities, for such period of time as the Transmission Provider continues to perform the balancing authority functions for the Market Coordination Customer under this Section.

90.2.5.5 If the Market Coordination Customer terminates service under this Part for any reason other than to become a Transmission Owner under the ISO Agreement, the Market Coordination Customer must make all necessary arrangements to resume all balancing authority obligations for its balancing authority area, or to have a NERC certified Balancing Authority assume those obligations, by the date upon which service under this Part will end. If the Market Coordination Customer has not made such arrangements by the date service under this Part III is to be terminated, such service, including the provision of Balancing Authority services by the Transmission Provider, shall continue until the Market Coordination Customer has completed such arrangements.

90.2.6 The Transmission Provider will act as the Reliability Coordinator for the Market Coordination Customer Transmission Facilities in accordance with the responsibilities specified in Part I of this Module F (but excluding Section 76 of this Tariff). For Market Coordination Customers taking service under Part I of Module F, the congestion management process described in Section 76 of the Tariff is replaced in its entirety by the terms and conditions for congestion management set forth in this Part.

90.2.7 The Transmission Provider will facilitate the coordination of transmission planning for the Combined Systems by providing the Market Coordination Customer with transmission planning information relevant to transmission service over the Combined Systems, including the Midwest ISO Plan, on request, and by conducting joint planning meetings and other requirements necessary to satisfy any state or federal regulatory requirements applicable to the planning process. If the Market Coordination Customer is a member of a regional planning group, the Transmission Provider will coordinate planning activities as described in this section with that regional planning group.

90.2.7.1 Nothing in this Part shall be construed to either permit or require the Market Coordination Customer to participate in the Midwest ISO Regional Expansion Criteria and Benefits ("RECB") process, or to have the Market Coordination Customer's transmission facility expansions included in the RECB allocations, or to permit or require the Transmission Provider to allocate any costs of the Transmission System to the Market Coordination Customer via the RECB process.

90.2.8 The Transmission Provider and each Market Coordination Customer shall coordinate System Impact Studies, Facilities Studies and generator interconnection studies conducted by the Transmission Provider with those conducted by each Market Coordination Customer (or conducted, on the Market Coordination Customer's behalf, by an independent transmission service coordinator or tariff administrator) for transmission service requests and generation interconnection requests over the Combined Systems:

90.2.9 The Transmission Provider shall coordinate the calculation of ATC/AFC/TTC pursuant to the mutually agreed-upon methodology indicated in the Service Agreement executed by the Market Coordination Customer pursuant to Section 96 and Attachment KK-3 of this Tariff. The ATC/AFC/TTC methodology will be posted on the Midwest ISO OASIS.

90.2.10 The Transmission Provider and each Market Coordination Customer will review system impact studies and facilities studies conducted by the Market Coordination Customer (or conducted on the Market Coordination Customer's behalf by an independent transmission service coordinator or tariff administrator) for tariff service that would result in a candidate request for an FTR or ARR, to determine whether of such service is simultaneously feasible, as provided in the Tariff.

90.3 Optional Tariff Administration And Related Services

Nothing in this Part III shall be interpreted to preclude the Transmission Provider and the Market Coordination Customer from entering into an agreement to provide optional tariff administration and related services.

90.4 Transmission Provider Discretion

The Transmission Provider shall have reasonable discretion in accordance with Good Utility Practice as to the manner in which it provides all services available under this Part III, provided that the Transmission Provider shall act in compliance with the provisions of this Part, the Funds Trust Agreement, applicable NERC and Regional Entity standards, and the applicable tariffs governing the Transmission System and the Market Coordination Customer Transmission Facilities.

91 Market Coordination Customer Obligations

91.1 The Market Coordination Customer shall: (i) execute the separate Service Agreements for the Market Coordination Service under this Part III, as set forth in Section 96 and Attachment KK-3 of this Tariff, and for the Reliability Coordination Service under Part I of Module F, as set forth in Section 74 and Attachment KK-1 of this Tariff; (ii) become a registered Market Participant pursuant to the Tariff before receiving Market Coordination Service under this Part to the extent that the Market Coordination Customer has a direct ownership or contractual interest in the resources specified under Section 90.2.1 and/or the Market Coordination Customer is a load serving entity under the Market Coordination Customer's tariff; (iii) ensure that any other resources and loads in the Customer Zone, excluding resources or loads in the Customer Zone Pseudo Tied out of the Midwest ISO Balancing Authority Area, are notified that they must be represented by a Market Participant; (iv) comply with all requirements, including all time limitations, for integrating the loads and resources in the Customer Zone, including loads and resources in the Customer Zone Pseudo Tied into the Midwest ISO Balancing Authority Area with the operation of the Energy and Operating Reserve Markets, as set forth in the Tariff and the related Business Practices Manuals.

91.2 The Market Coordination Customer shall calculate the components of available transmission capability and available flowgate capability for its transmission facilities in accordance with NERC and Regional Entity requirements binding on the Market Coordination Customer by way of contract, or provided on the Market Coordination Customer's behalf by an independent transmission service coordinator or tariff administrator.

91.3 A Market Coordination Customer taking service under this Part shall offer to provide the equivalent of Other Ancillary Services to transmission customers taking service under the Market Coordination Customer's tariff. All such services will be provided and offered under rates, terms and conditions that are consistent with Commission regulations and orders, to the extent applicable. The Market Coordination Customer shall not be required to continue to provide and offer these services if the Commission no longer requires a utility operating as a balancing authority to offer them. All Market Participants, including Market Participants representing loads and/or resources in a Customer Zone, shall have a Regulating Reserve obligation as specified under Section III of Schedule 3 of this Tariff, a Spinning Reserve obligation as specified under Section III of Schedule 5 of this Tariff, and a Supplemental Reserve obligation as specified under Section III of Schedule 6 of this Tariff. Market Participants may satisfy these obligations as specified under Schedules 3, 5 and 6 of this Tariff. A Market Coordination Customer providing Regulating Reserve, Spinning Reserve and Supplemental Reserve to its transmission customers in its Customer Zone under Schedules 3, 5, and 6 of its tariff shall obtain such services from the Midwest ISO Energy and Operating Reserve Market.

91.4 As a condition of receiving any services under this Part, the Market Coordination Customer shall revise its tariff to include the *pro forma* Market Integration Transmission Service tariff provisions, as set forth as Attachment MM of this Tariff.

91.5 The Market Coordination Customer shall provide the Transmission Provider, as required by and in the time limitations contained in the Tariff and Business Practices Manuals, with all such information as is reasonably necessary for the Transmission Provider to provide the services under this Part. Such information, if deemed to be CEII or confidential shall be so designated by the Market Coordination Customer and will be treated as such by the Transmission Provider in accordance with the Tariff and applicable Commission regulations. The information required by the Transmission Provider includes, but is not limited to, the following:

91.5.1 transmission planning information for transmission facilities that has an impact on transmission service over the Combined Systems;

91.5.2 notice of granting any application for network integration transmission service under the Market Coordination Customer's transmission tariff and the time of receipt of said application(s);

91.5.3 notice of granting any applications for firm point-to-point transmission service under the Market Coordination Customer's tariff and the time of receipt of said application(s);

91.5.4 notice of granting any applications for network resource interconnection service under the Market Coordination Customer's tariff and the time of receipt of said application(s);

91.5.5 all resources and loads that are required to be modeled in the Network Model and the Commercial Models; and

91.5.6 any additional information reasonably required by the Transmission Provider to provide services to all Market Coordination Customers pursuant to this Part.

91.6 All transmission service priorities and curtailments shall be governed by the Tariff, the Market Coordination Customer's tariff, and applicable NERC/NAESB requirements.

91.7 Upon termination of service under this Part, for any reason other than to become a signatory to the ISO Agreement: (i) the Market Coordination Customer shall provide to transmission customers of other Market Coordination Customers taking service under this Part at the time the notice of termination is served such firm transmission service (under the rates, terms and conditions of the terminating Market Coordination Customer's tariff) in the form of Market Integration Transmission Service or such other firm transmission service as the other transmission customers may request to effect the Security Constrained Economic Dispatch for those customers; (ii) the Market Coordination Customer shall grant firm service to any designated Network Resources on the Market Coordination Customer Transmission Facilities supplying designated Network Load on the Transmission System for the duration of the reservation of service under the Market Coordination Customer's tariff, including rollover rights when the term of the supply contract qualifies for such service under the terms and conditions of the Market Coordination Customer's transmission tariff.); and, (iii) the Transmission Provider shall grant firm service to any designated Network Resources on the Transmission System supplying designated Network Load on a Market Coordinator Customer Transmission System for the duration of the reservation of service under the Tariff. (The Transmission Provider shall grant long-term firm service and rollover rights when the term of the contract qualifies for such service under the terms and conditions of its Tariff.)

91.7.1 Provided, however, that the obligations set forth in subparts (i), (ii) and (iii) of section 91.7 shall be subject to available transmission capacity on the transmission systems of the Market Coordinator Customer and the Transmission Provider, and that neither the Market Coordination Customer nor the Transmission Provider shall have an obligation to build or expand their respective transmission facilities at the time service is terminated under this Section to implement the service required by Section 91.7 (i), (ii) and (iii) of this Tariff, except as provided in this Tariff and the transmission tariff of the Market Coordination Customer.

92 Congestion Management

92.1 The Transmission Provider will employ the Security Constrained Economic Dispatch of the resources within the Midwest ISO Balancing Authority Area, including the resources in each Customer Zone, as described in Module C of this Tariff, as a congestion management mechanism to reduce or eliminate congestion on the Combined Systems.

92.2 The Transmission Provider shall model and identify flows over the Market Coordination Customer Transmission Facilities in order to monitor congestion on the Market Coordination Customer Transmission Facilities caused by flows from the Combined Systems, from transmission customers under the Market Coordination Customer's tariff, and the transmission systems of Reciprocal Entities.

92.3 In order to coordinate third-party transmission providers' use of curtailment procedures and generation redispatch for the relief of transmission congestion on third-party transmission facilities (including operating entities taking only the Reliability Coordination Service under Part I of this Module F) with the Transmission Provider's use of economic redispatch for the relief of transmission congestion on the Combined Systems and the congestion management procedures of Reciprocal Entities, the Transmission Provider will offer the Congestion Management Services under Part II of this Module F, containing the procedures set forth in Attachment LL of this Tariff.

92.4 In the application of existing or future congestion management agreements between the Transmission Provider and third party transmission providers using the CMP methodology, the flows of Market Coordination Customers taking service pursuant to this Part shall be included with the market flows of the Transmission Provider to calculate impacts on Coordinated Flowgates and Reciprocal Coordinated Flowgates.

92.5 The Market Coordination Customer may designate an independent transmission service coordinator or tariff administrator as the manager for studies regarding the forward coordination process for the Market Coordination Customer's Flowgates. If no such designation is made, the Transmission Provider will manage the studies for the Market Coordination Customer's Flowgates.

93 Transmission Service Arrangements

93.1 Transmission Service by Transmission Provider

The Transmission Provider shall provide Market Integration Transmission Service to Market Coordination Customers to effectuate Market Coordination Service under Part III of Module F. Market Integration Transmission Service shall not be available for any other purpose or to entities that are not Market Coordination Customers or Market Participants. The terms and conditions of service applicable to Point-to-Point Transmission Service and Network Integration Transmission Service provided under Module B of this Tariff shall not apply to Market Integration Transmission Service. The following terms and conditions shall apply to Market Integration Transmission Service:

93.1.1 The Transmission Provider shall provide Market Integration Transmission Service only on the facilities that comprise the Transmission System.

93.1.2 Market Integration Transmission Service shall be a firm hourly Transmission Service.

93.1.3 The Transmission Provider shall not require an application for service to provide Market Integration Transmission Service. No separate service agreement shall be required to provide Market Integration Transmission Service to any Market Coordination Customer that has executed a Service Agreement pursuant to Attachment KK-3 of this Tariff.

93.1.4 Market Integration Transmission Service shall be provided on an "as-available" basis, as determined by the Security Constrained Economic Dispatch For this reason, no reservation, tag, or schedule shall be required to obtain Market Integration Transmission Service, and the Transmission Provider shall not be required to post or decrement Available Transfer Capability or Available Flowgate Capability associated with Market Integration Transmission Service on its OASIS.

93.1.5 Market Integration Transmission Service shall be offered by the Transmission Provider to effectuate transactions in the Energy and Operating Reserve Market. Market Integration Transmission Service shall not be eligible for annual Auction Revenue Rights or Financial Transmission Rights.

93.1.6 The rates, charges and additional terms and conditions applicable to the Transmission Provider's Market Integration Transmission Service are set forth in Schedule 32 of this Tariff.

93.1.7 The Transmission Provider undertakes no obligation under this Tariff to plan or construct its Transmission System in order to have sufficient capacity for Market Integration Transmission Service.

93.2 Transmission Service by Market Coordination Customer

93.2.1 The Market Coordination Customer shall provide transmission service under its tariff to permit the Transmission Provider to provide service under this Part III of this Module F to the Market Coordination Customer and other Market Coordination Customers. To that effect, the Market Coordination Customer shall adopt in its tariff terms and conditions that are consistent with or superior to the pro forma provisions set forth in Attachment MM of this Tariff and shall comply with all other requirements set forth in Part III of this Module F.

93.2.2 A Market Participant that is located in a Customer Zone of a Market Coordination Customer shall comply with the transmission service provisions that are established by Market Coordination Customers pursuant to Section 93.2.1 of this Tariff.

93.3 Designating Network Resources

93.3.1 Network Load taking transmission service from the Transmission Provider may designate resources which are connected to the transmission system of a Market Coordination Customer, or network load taking network transmission service from a Market Coordination Customer may designate a network resource connected to the Transmission Provider's Transmission System. Resources not connected to the Transmission System must satisfy the requirements of Section 30.6 of the Tariff to become designated Network Resources under the Transmission Providers Tariff.

93.3.2 A resource connected to the transmission system of a Market Coordination Customer will be deemed to have complied with the requirements of Section 30.6 of this Tariff if: (i) the Market Coordination Customer's tariff requires such resources to meet the requirements set forth in Section 69 of the Transmission Provider's Tariff and the Transmission Provider determines that the resource has met the requirements set forth in Section 69 of this Tariff; and (ii) the Transmission Provider determines that the terms and conditions for designating and removing network resources, as defined in the Market Coordination Customer's transmission tariff and business practices, including the requirements set forth in this Section 93.3.2, are comparable to the terms and conditions applicable to designating and removing Network Resources under the Transmission Provider's Tariff.

93.4 Reciprocity

It is a continuing condition of service under this Part that: (i) the Market Coordination Customer and any of its power marketing affiliates shall be entitled to all forms of Transmission Service available under the Tariff, and (ii) all Market Participants and Eligible Customers under this Tariff, all Market Coordination Customers taking Market Coordination Service under this Part, and all Transmission Customers shall be entitled to all forms of transmission service available under the Market Coordination Customer's tariff. Failure of this condition to be fulfilled shall result in either the immediate termination or suspension of service under this Part, or default under this Tariff, whichever is applicable. Nothing in Section 6 of the Tariff shall be interpreted to modify or diminish the obligations of Market Coordination Customers set forth in this Section 93.4 and/or Attachment MM of the Tariff.

93.5 Single Customer Zone

Two or more Market Coordination Customers taking service under this Part whose Market Coordination Customer Transmission Systems are interconnected may enter into a transmission service and revenue sharing agreement and request that their individual zones be combined into a single Customer Zone. The Transmission Provider will analyze the proposed Customer Zone and if the proposed rate zone does not result in financial or operating detriment to other Market Coordination Customers taking service under this Part, or to other Market Participants or Transmission Owners, the Transmission Provider will enter into a supplemental Service Agreement with the Market Coordination Customers for this purpose. For the purposes of transmission service pricing, resources and load connected directly to the Market Coordination Customer's transmission facilities shall be considered to be in only that Customer Zone.

94 Compensation for Services

94.1 The Transmission Provider shall bill the Market Coordination Customer and the Market Coordination Customer shall pay the Transmission Provider for services provided under Part III of this Module F in accordance with this Section 94 and the billing and payment terms set forth in Article 7 of the Tariff. All Market Participants shall be billed for, and shall pay for services provided under this Tariff pursuant to the billing and payment terms set forth in Article 7 of the Tariff, as such terms may be modified from time to time by an order of the Commission.

94.2 Market Coordination Customers taking Market Coordination Service shall pay all applicable charges that may be required by Modules A, C, D, E and F, including without limitation charges required under (i) Schedule 16 of this Tariff for financial transmission rights, (ii) Schedule 17 of the Tariff for energy market transactions, and (iii) Schedule 32 of this Tariff for Market Integration Transmission Service required by the Market Coordination Customer to integrate the resources and loads of its transmission customers. Charges for Reliability Coordination Service under Part I of this Module F taken in conjunction with the services provided under this Part shall be paid as set forth in Part I of this Module F.

94.3 Upon termination of the applicable Service Agreement, if the Market Coordination Customer does not become a Transmission Owner, the Market Coordination Customer shall be responsible for payment of: (a) an allocated share of the remaining book value of all Incremental Reliability Coordination Assets, and (b) an allocated share of the remaining book value of all incremental capital assets associated with the provision of Market Coordination Service ("Incremental Energy Market Assets") and for certain financing costs associated with the Incremental Energy Market Assets as set forth in Section 94.3.1 to 94.3.3 of this Tariff. For the purposes of this Section 94.4 of this Tariff the calculation of the value for Incremental Reliability Coordination Assets shall be as described in Section 77.3.1 to Section 77.3.3 of this Tariff.

94.3.1 The calculation of the value for Incremental Energy Market Assets shall be the sum of: (a) the remaining book value of all capital assets associated with the provision of Market Coordination Service that were placed into service on or after December 31, 2007; and (b) the balance of all work in progress on assets associated with the provision of Market Coordination Service as of the date of termination.

94.3.2 In addition to payment owed for an allocated share of Incremental Reliability Coordination Assets and Incremental Energy Market Assets, the Market Coordination Customer shall be responsible for payment of an allocated share of the remaining interest expense over the life of any outstanding debt issued subsequent to December 31, 2007 used to finance the development or acquisition of capital assets associated with the provision of Reliability Coordination Service and Market Coordination Service that were placed into service on or after December 31, 2007. The Market Coordination Customer shall also be responsible for payment of an allocated share of any remaining payments associated with lease obligations incurred after December 31, 2007 used to finance the development or acquisition of assets associated with the provision of Reliability Coordination Service and Market Coordination Service that were placed into service on or after December 31, 2007.

94.3.3 In computing the financial obligations outstanding as of the date of termination, the lump sum amount owed under this Section 94.3 that is associated with remaining interest payments over the life of the outstanding debt that is associated with the provision of Reliability Coordination Service and Market Coordination Service shall be discounted to a net present value amount with the discount rate used equal to the expected interest rate to be earned on funds held in the investment account of the Transmission Provider.

94.3.4 The Market Coordination Customer shall also be responsible for payment of an allocated share of the accrued current liabilities on the balance sheet of the Transmission Provider as of the date of termination of the Service Agreement.

94.3.5 The Market Coordination Customer shall pay a load ratio share of these incremental financial obligations. The load ratio share shall be calculated as the Market Coordination Customer's monthly peak demand for the twelve months preceding the termination of the Service Agreement, relative to the sum of the monthly peak demand during that period of all Market Coordination Customers and all Tariff Customers receiving Network Integration Transmission Service under the Tariff. All peak demand information shall be converted into Maximum Energy Transfer data as defined in Part II, Section A, of Schedule 10 of this Tariff. The Transmission Provider shall use the non-coincident peak demand for each Market Coordination Customer multiplied by the number of hours in a month to derive the Market Coordination Customer's Maximum Energy Transfer value. The Transmission Provider shall compute Maximum Energy Transfer values for its Tariff Customers taking Network Integration Transmission Service during the preceding month from their non-coincident peak demand. The Market Coordination Customer shall pay the entire amount owed under this Section 94 at the time the applicable Service Agreement is terminated.

94.3.6 As to a Market Coordination Customer to which Section 12E of this Tariff applies, the obligation to make the payments under this Section is subordinate and junior in all respects to the obligation of the Market Coordination Customer to pay the principal and interest on its bonds.

95 Joint Coordinating Committee

95.1 A Joint Coordinating Committee is hereby established. The Transmission Provide and each Market Coordination Customer taking service under this Part III of Module F shall be a voting member of the Joint Coordinating Committee.

95.2 The Transmission Provider and each Market Coordination Customer taking service pursuant to this Part III of Module F shall appoint one representative to the Joint Coordinating Committee and each party shall pay the expenses of its representative to the Joint Coordinating Committee.

95.3 A member's Joint Coordinating Committee representative shall be a person of reasonable competency and with such authority as to uphold the decisions made to the extent such decisions do not require formal approval under governing state laws and regulations.

95.4 The Joint Coordinating Committee shall meet at least quarterly during the first year after the effective date of this Part, and shall meet periodically thereafter as the Joint Coordinating Committee shall, by a majority vote of three-fourths of those entitled to vote, determine to be necessary to administer its duties under this Part in a reliable and efficient manner.

95.5 In cooperation with the Transmission Provider, and consistent with the requirements of the Tariff and all applicable reliability standards, the Joint Coordinating Committee shall:

95.5.1 review procedures for the implementation of the operating and technical requirements of this Part;

95.5.2 identify procedures for coordinating and integrating the operating and technical requirements of this Part with those of Part I of Module F;

95.5.3 periodically meet with and incorporate suggestions from the Reliability Coordinating Technical Committee created under Part I of Module F;

95.5.4 participate in the development of Business Practices Manuals for the administration of this Part on a reliable and economically efficient basis; and

95.5.5 address any other matters referred to herein or necessary for implementation, administration or operation of this Part.

95.6 The Joint Coordinating Committee shall create and direct such subcommittees, task forces or work groups as it deems appropriate to address technical or other operating issues.

95.7 Recommendations and other actions the Joint Coordinating Committee shall be by a three-fourths majority of those present and entitled to vote under the rules adopted by the Joint Coordinating Committee to govern its proceedings. Nothing herein shall prohibit the Joint Coordinating Committee from developing rules and procedures regarding proxy voting, and procedures to allow electronic meeting or voting.

95.8 All proceedings and decisions of the Joint Coordinating Committee shall be reduced to writing and approved by the Joint Coordinating Committee representatives, but shall not be inconsistent with and shall not serve to contradict any terms or conditions of this Part in effect at the time of such procedures or decisions being made or developed.

95.9 Market Coordination Customers taking service under this Part shall be eligible to participate in the Transmission Provider's stakeholder process as members of the Coordinating Members segment.

95.10 Participation in the activities of the Joint Coordinating Committee by the Transmission Provider or by the Market Coordination Customer shall not constitute a waiver by that party of any of its rights under the Federal Power Act to initiate a proceeding, make any other filing, or advance any position regarding any matter before the Commission.

96 Service Agreement

96.1 The Transmission Provider shall offer a standard form Service Agreement for Market Coordination Service to the entity eligible to receive service under Part III of this Module F. Executed Service Agreements entered into pursuant to this Section 96 shall be filed with the Commission in compliance with applicable Commission regulations. The standard form of Service Agreement for Market Coordination Services is provided in Attachment KK-3 to this Tariff.

96.2 If the Commission determines that regulatory filings are required to implement the Service Agreement executed pursuant to this Section 96, the Transmission Provider and the Market Coordination Customer shall cooperate with each other as necessary and appropriate to facilitate any such required Commission filings.

97 Term

97.1 The initial term of Market Coordination Service shall be for a period of three (3) years after the effective date of the Service Agreement executed pursuant to Section 96 and Attachment KK-3 of this Tariff. The Service Agreement shall automatically renew thereafter for successive one-year terms unless written notice of termination is provided not less than one year prior to the end of the initial term or a subsequent term. The effective date of the Service Agreement shall be the date set forth therein or any other date as may be established by the Commission.

97.2 A Market Coordination Customer to which Section 12E of this Tariff applies may terminate its Service Agreement executed pursuant to Section 96 and Attachment KK-3 of this Tariff at any time during the initial term or any extension thereof with less than the required one-year notice, in the event that the statutes governing such Market Coordination Customer, or any provisions of this Part III of Module F, or the provisions of the Transmission Provider's Tariff incorporated by reference in this Part III of Module F are changed or modified, in a manner that causes a conflict with state law, regulations, or rate schedules and the review process described in Section 12E of this Tariff is unable to resolve such conflict.

97.3 Upon written notice to the Transmission Provider that the Market Coordination Customer is exercising its right to terminate its Service Agreement pursuant to Section 97.2 of this Tariff, the Transmission Provider and the Market Coordination Customer will work in good faith to make all required arrangements to adjust the commercial and network models used by the Transmission Provider to provider service under this Part III, and to arrange for a transfer of the balancing authority responsibilities to another balancing authority or to the Market Coordination Customer, in order to permit the Market Coordination Customer to terminate service under this Part III on the earliest possible date.

97.4 Upon termination of service under this Part, the Market Coordination Customer and the Transmission Provider shall each remain responsible for their respective financial obligations, if any, incurred under this Part prior to termination until completion of any such obligation.

SCHEDULE 31

Reliability Coordination Service Cost Recovery Adder

Definitions:

Maximum Energy Transfer for Reliability Coordination Service – the result of multiplying the Reliability Coordination Customer Monthly Peak for the month by the number of hours in the month.

Reliability Coordination Customer Monthly Peak—the non-coincident monthly peak load of the Reliability Coordination Customer. The non-coincident monthly peak load of the Reliability Coordination Customer shall include all wholesale and retail load within the Balancing Authority Area of the Reliability Coordination Customer, or that is interconnected with and taking service over the transmission facilities of the Reliability Coordination Customer, but shall not include load that pays for Reliability Coordination Service separately under Part I of Module F, or pays for reliability coordination service from another Reliability Coordinator other than the Transmission Provider.

I. GENERAL

The Transmission Provider will recover its costs to provide Reliability Coordination Service pursuant to the terms of this Schedule 31 from Reliability Coordination Customers that execute the applicable Service Agreement as set forth in Section 74 and Attachment KK-1 to the Tariff. The costs recovered pursuant to the terms of this Schedule 31 are exclusive of those costs recovered pursuant to Schedules 1, 10, 10-A, 10-B, 10-C, 16, 16-A, 17 or 17-A of this Tariff. Part II of this Schedule 31 presents the cost recovery formula and charges applicable to all Reliability Coordination Customers.

The cost recovery formula and charges in Part II of this Schedule applicable to the *Maximum Energy Transfer for Reliability Coordination Service* shall be billed to and recovered from Reliability Coordination Customers based on the physical location of the Reliability Coordination Customer's load as described in Part II, Section B of this Schedule 31.

II. RELIABILITY COORDINATION SERVICE COST RECOVERY ADDER

The charges applicable to each Reliability Coordination Customer shall be the product of the monthly rate for service under this Schedule 31 and the Maximum Energy Transfer for Reliability Coordination Service.

Each monthly charge shall be calculated based on budgeted costs and forecasted *Maximum Energy Transfer for Reliability Coordination Service* and will be trued up in the following month's calculation to reflect actual costs and actual Maximum Energy Transfer for Reliability Coordination Service.

Determination of the Monthly Charge

The monthly charge for Reliability Coordination Service shall be based on a subset of the costs recovered under Schedule 10 of the Tariff. The subset of costs shall be those associated with the performance of the Reliability Coordination Service as set forth in Part I of Module F. For budgeting and cost recovery purposes the Transmission Provider shall allocate a portion of its Schedule 10-related operating costs to the reliability coordination functions based on an analysis of the functions performed by each department and by each employee. Allocation of capital-related costs, including depreciation expense, interest expense and amortization of deferred regulatory assets, shall be based on the purpose and use of each asset. The end result of the cost allocation process shall be a set of financial records for each cost recovery category maintained in accordance with the FERC Uniform System of Accounts.

The recording of salaries and benefits to the financial accounting books and records of the Transmission Provider is based on time sheet entries. All other operating expenses are then either directly recorded to the appropriate set of financial records or allocated to the appropriate set of financial records using salary-based labor allocation factors other appropriate allocation factors. All capital-related costs are either directly recorded to the appropriate set of financial records or allocated to the appropriate set of financial records using salary-based labor allocation factors or other appropriate allocation factors.

The cost allocation process described above shall be used by the Transmission Provider to first allocate costs to Schedule 10 and then to the Reliability Coordination Service functions that are a subset of its Schedule 10-related services. The categories of services provided under Schedule 10 of the Tariff are:

1. Reliability Coordination – ensuring the reliable operation of the bulk power system in accordance with NERC Standards and other requirements, including:
   a. Operations Planning – development of operational plans to respond to system conditions and potential contingency situations
   b. Maintenance Coordination – reviewing and approving or denying requests for scheduled transmission line outages, and coordinating generating unit outages
2. Tariff Administration – reviewing and approving or denying requests for Transmission Service.
3. Scheduling – reviewing and approving or denying schedules for use of confirmed transmission reservations.
4. Billing & Settlements – computation of charges, invoicing, and revenue distribution
5. Transmission Planning – including all studies associated with requests for long term firm transmission service, requests for generation interconnection service, and development of the Midwest ISO Transmission Expansion Plan ("MTEP") document approved by the board of directors.

The costs to be recovered from Reliability Coordination Customers under this Schedule 31 are those associated with the performance of the Reliability Coordination Service as set forth in Part I of Module F.

The allocation of costs into subcategories of Schedule 10-related service is performed separately for: (1) Operating Expenses, and (2) Fixed Cost Recovery. Operating Expenses include all costs shown on the Schedule 10 income statement of the Transmission Provider except the following: (a) FERC Fees, (b) depreciation, (c) amortization, and (d) other income/(expense). Fixed Cost Recovery includes the costs shown on the Schedule 10 income statement of the Transmission Provider that are associated with: (a) depreciation, (b) amortization, and (c) other income/(expense). The fixed costs recovered under this Schedule 31 exclude certain depreciation and amortization expenses as described in more detail below.

Operating Expense Recovery

The Transmission Provider shall allocate Operating Expenses to the appropriate subcategories of Schedule 10-related services based on a department-by-department review of the costs incurred by each department. All indirect costs are allocated based on the ratio of direct labor costs allocated to Reliability Coordination Service functions divided by the total of all direct labor costs to be recovered under Schedule 10 of the Tariff.

The initial cost of the Schedule 10-related Reliability Coordination functions as a percent of the total budgeted Schedule 10 operating costs based on budget data for 2007 is summarized in Table 1 below. The initial cost allocation percentages for Operating Expenses to be recovered under Schedule 31 shall remain in effect until April 1, 2008. During March 2008, the Transmission Provider shall update the cost of service study based on actual costs incurred during 2007 and budgeted costs for 2008. The updated cost allocation percentages shall remain in effect until April 1, 2009. The process of updating the Schedule 10 Operating Expense Allocation Factor shall be repeated annually.

Table 1

Reliability Coordination Service Schedule 10 Operating Expense Allocation Factor

Schedule 10 Service Category	Percent of Schedule 10 Operating Costs
Reliability Coordination	40.3%
Operations Planning	1.7%
Maintenance Coordination	9.4%
Total – Reliability Coordination Service	51.4%

Fixed Cost Recovery

Fixed Cost Recovery for the purposes of Schedule 31 shall include: (a) certain depreciation as set forth in this Schedule 31; (b) certain amortization expenses as set forth in this Schedule 31; and (c) certain interest expense recorded as other income/(expense) as set forth in this Schedule 31.

For the purposes of this Schedule 31, the depreciation expense shall be Schedule 10 depreciation expense net of depreciation associated with the initial capital costs to develop the Integrated Control Center System placed into service on February 1, 2002 and depreciated over seven (7) years. During 2007 and 2008 a proxy value for the depreciation expense net of depreciation associated with the initial capital costs to develop the Integrated Control Center System placed into service on February 1, 2002 shall be used. The initial proxy value for total Schedule 10 deprecation net of the initial capital costs to develop the Integrated Control Center System is $12,405,841.

The initial cost allocation percentages for Fixed Cost Recovery shown in Table 2 shall remain in effect until April 1, 2008. During March of 2008, the Transmission Provider shall update the proxy value in the preceding paragraph to reflect any changes to (a) the capital expenditures forecasted to have been incurred during 2007, (b) the forecast of capital expenditures scheduled to occur in 2008, and (c) the forecast of capital expenditures scheduled to occur in 2009. The initial cost allocation percentages in Table 2 shall remain in effect until April 1, 2009. The process of updating the Schedule 10 Fixed Cost Allocation Factor shall be repeated annually thereafter.

Table 2

Reliability Coordination Service – Schedule 10 Fixed Cost Allocation Factor

Service Category	Percent of 2009 Schedule 10 Depreciation
Reliability Coordination	26.1%
Operations Planning	3.3%
Maintenance Coordination	3.0%
Total Reliability Coordination Service	32.4%

For the purposes of this Schedule 31 the recovery of amortization expenses shall exclude those associated with: (a) pre-operating expenses for Day One development, (b) pre-operating expenses for Day Two development, (c) deferral of $25 million for future recovery under settlement agreement with Transmission Owners, and (d) all GridAmerica and Alliance RTO costs paid to GridAmerica, Ameren, and Illinois Power (see Footnote No. 4 to the audited financial statements of the Transmission provider for period ending 12/31/2006).

Interest expense and interest income allocated to Schedule 10 shall be allocated to the appropriate subcategories in Table 2 based on the depreciation allocation factor for each subcategory in Table 2. For the purposes of this Schedule 31, interest expense shall be that associated existing debt, including the senior, unsecured notes issued by the Transmission Provider, that is allocated to Schedule 10 for cost recovery purposes as delineated in the Tariff. Interest expenses shall also include that expense associated with the issuance of any new debt to finance incremental capital improvements that are to be recovered under Schedule 10.

Payments Applicable to Withdrawing Reliability Coordination Customers

In the event that a Reliability Coordination Customer withdraws its transmission facilities from the reliability coordination authority of the Transmission Provider pursuant to a termination notice under Part I, Module F of the Tariff and the Applicable Service Agreement, the withdrawing Reliability Coordination Customer shall pay its share of all incremental Schedule 31-related financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal as set forth in, and subject to the terms and conditions of, Section 77.3, Part I of Module F.

A. RATES AND BILLING UNITS/DETERMINANTS

Each month, the Transmission Provider shall determine the billing rate for application under this section. The formula for determining the Reliability Coordination Service monthly rate is as follows:

$$REL\_R_t = [((TMRA_t - DEPR10_t - AMORT10_t - INT\_EXP10_t - COST\_10A_t - COST\_10B_t - COST\_10C_t - CREDIT\_10A_t - CREDIT\_10C_t) * RSOP\_EXP\%) - MCSG\_REV_t + REL\_TRUEUP_{t-1} + ((DEPR\_RF_t + INT\_EXP10_t) * RS\_FCR\%)] / [(FMET_t + REL\_MWH_t - MSCG\_MWH_t)]$$

where:

t =	the effective month.
REL_R =	the rate per MWh of Maximum Energy Transfer for Reliability Coordination Service to be charged to Reliability Coordination Customers under Schedule 31.
TMRA -	the Targeted Monthly Recovery Amount as defined in Part II, Section A of Schedule 10 of the Tariff.
DEPR10 -	the portion of the Targeted Monthly Recovery Amount associated with depreciation expense recovered under Schedule 10 of the Tariff.
AMORT10 –	the portion of the Targeted Monthly Recovery Amount associated with amortization expense recovered under Schedule 10 of the Tariff.

INT_EXP10 = the portion of the Targeted Monthly Recovery Amount associated with interest expense recovered under Schedule 10 of the Tariff net of interest income allocated to Schedule 10 of the Tariff.

COST_10A = the projected costs to be recovered under Schedule 10-A of the Tariff as defined in Part II, Section A of Schedule 10 of the Tariff.

COST_10B = the projected costs to be recovered under Schedule 10-B of the Tariff as defined in Part II, Section A of Schedule 10 of the Tariff.

COST_10C = the projected costs to be recovered under Schedule 10-C of the Tariff as defined in Part II, Section A of Schedule 10 of the Tariff.

CREDIT_10A = the monthly amortization amount of the Schedule 10 Withdrawal Obligation paid by Commonwealth Edison Company as defined in Part II, Section A of Schedule 10 of the Tariff.

CREDIT_10C = the monthly amortization amount of the Schedule 10 Withdrawal Obligation paid by LGE/KU as defined in Part II, Section A of Schedule 10 of the Tariff.

RSOP_EXP% = Reliability Coordination Service Schedule 10 Operating Expense Allocation Factor from Table 1 in this Part II, Section A of Schedule 31.

MCSG_REV = projected revenue to be recovered from the MCSG Participants from the provision of Reliability Coordination Services under a contract between the Transmission Provider and the MCSG Participants dated January 22, 2008.

REL_TRUEUP = the sum of: (i) the difference between the actual revenue collected during the prior month from the provision of Reliability Coordination Service under this Schedule 31 and the actual cost of Reliability Coordination Service under this Schedule 31 during the prior month, and (ii) the difference between the actual revenue collected during the prior month under the MCSG Agreement and the actual cost of Reliability Coordination Service recovered under the MCSG Agreement.

DEPR_RF = the portion of the Targeted Monthly Recovery Amount for depreciation expense associated with all Schedule 10-related capital expenditures exclusive of the cost of the Integrated Control Center System placed into service on February 1, 2002 computed by multiplying the projected Schedule 10-related depreciation for 2009 in the amount of $12,405,841 by the fixed cost allocation factor in Table 2 of Section II, Part A of this Schedule 31.

RS_FCR% the Reliability Coordination Service Fixed Cost Allocation Factor from Table 2 in this Part II, Section A of Schedule 31.

FMET the Transmission Provider's forecast of Maximum Energy Transfer in MWhs as defined in Section II, Part A of Schedule 10.

REL_MWH = the Transmission Provider's forecast of Maximum Energy Transfer for Reliability Coordination Service provided under Part I of Module F.

MCSG_MWH = the Transmission Provider's forecast of Maximum Energy Transfer for Reliability Coordination Service provided under the MCSG Agreement.

B. CHARGES

The following formula shall be used to calculate the monthly Schedule 31charges to each Reliability Coordination Customer:

$REL\_FEE_t = (REL\_R_t \times RS\_MWH_t)$ where:

t = the effective month.

REL_FEE = Schedule 31 charges associated with Reliability Coordination Service for the Customer for that month.

REL_R = the Reliability Coordination Service rate established by the Transmission Provider in accordance with Part II, Section A of this Schedule 31.

RS_MWH = the MWhs of Maximum Energy Transfer of the Reliability Coordination Customer.

SCHEDULE 32

Market Integration Transmission Service

The Market Coordination Customer shall compensate the Transmission Provider each month for the applicable Market Integration Transmission Service charges set forth below, in addition to other applicable charges specified in this Tariff.

A. MARKET INTEGRATION TRANSITION PERIOD CHARGES

(1) **Market Integration Transition Period:** For purposes of this Schedule, the "Market Integration Transition Period" shall be defined as the first three years (thirty-six (36) calendar months) from the first time that the first Market Coordination Customer takes service under Part III of Module F of this Tariff, but shall not exceed 4 years from the effective date established by the Commission for service under Part III of Module F. The charges applicable during the Market Integration Transition Period are set forth in Part A of this Schedule. Part B of this Schedule will be used for any period subsequent to the Market Integration Transition Period.

(2) The charges for Market Integration Transmission Service taken during the Market Integration Transition Period shall be determined as follows:

Market Integration Transmission Service charge for each year during the Market Integration Transition Period shall be equal to charges assessed to the Market Coordination Customer during the calendar year prior to the effective date of the Service Agreement executed by the Market Coordination Customer pursuant to Section 96 and Attachment KK-3 of this Tariff. The charge shall include all applicable charges for transmission service incurred during such calendar year to the Interface that represented the Market Coordination Customer.

(3) The Market Coordination Customer shall compensate the Transmission Provider each month for Market Integration Transmission Service. The monthly charge shall be one-twelfth of the total charge calculated in Part A (2).

B. MARKET INTEGRATION TRANSMISSION SERVICE CHARGES AFTER THE TRANSITION PERIOD

Part B of this Schedule shall apply to Market Integration Transmission Service taken after the end of the Market Integration Transition Period by each Market Coordination Customer.

All effective rates under Part B shall be posted on the Transmission Provider's OASIS. The rate is calculated using the formula included in Attachment O, pages 1 and 2. The rate will be recalculated each June 1 based on the prior full calendar or fiscal year.

(1) **Single System – Wide Rate:** The Market Coordination Customer shall pay the applicable single system rate for Market Integration Transmission Service

(2) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Market Coordination Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for Market Integration Transmission Service, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Market Coordination Customers.

(3) Average Hourly Market Integration Transmission Service Demand: The average demand by a Market Coordination Customer is calculated by summing the positive hourly demand over the previous calendar year from the Transmission System to the Market Coordination Customer's transmission system and dividing by the number of hours in a year.

The Transmission Provider shall determine the Amount of service for Market Integration Transmission Service taken by each Market Coordination Customer and calculate the applicable charge for Market Integration Transmission Service as follows:

a. The Transmission Provider shall calculate a monthly charge for Market Integration Transmission Service for each Market Coordination Customer by applying the applicable Single - System Wide Rate to the Average Hourly Market Integration Transmission Service Demand.

(i) The Average Hourly Market Integration Transmission Demand is adjusted for pre-arranged transmission service under this Tariff to the Market Coordination Customer transmission system.

POLICY INTENT:

This Credit Policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and Applicants pursuant to one or more Credit and Security Agreement(s), and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event the Applicant and/or Tariff Customer does not satisfy the financial requirements to establish Unsecured Credit to cover its Total Potential Exposure.

This policy also sets forth: (i) the basis for establishing the individual Total Credit Limit that will be imposed on an Applicant and/or Tariff Customer in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements and (ii) various obligations and requirements the violation of which will result in a Default pursuant to this policy, this Tariff and the Agreements.

The Transmission Provider shall administer and implement the terms of this Credit Policy.

APPLICABILITY:

This policy applies to all Applicants and Tariff Customer who take Transmission Service under this Tariff, utilize services or participate in the Energy Markets, hold FTRs, or otherwise participate in Market Activities under Module C of this Tariff. This policy also applies to Reliability Coordination Customers, Congestion Management Customers and Energy Market Coordination that take service under Module F of this Tariff.

NOTICE:

All written notifications by the Transmission Provider under this policy shall be in accordance with Section 7.15 of this Tariff. Notifications to Applicants and/or Tariff Customer will be sent to their credit contact.

IV. Potential Exposure to Non-Payment and Total Potential Exposure

Potential exposure to non-payment is calculated separately for each category of Markets and Services. The information in Section IV of this Credit Policy addresses the calculation and use of the value for Total Potential Exposure by Participant, Reliability Coordination Customers, Congestion Management Customer or Energy Market Coordination Customer.

A. Total Potential Exposure

For credit purposes, a Tariff Customer's Total Potential Exposure shall be the sum of the charges and credits for the following service categories as calculated per the formulas in Section IV of this Credit Policy:

1. Real-Time Energy Market
   - Including all charge types associated with Congestion Management Service under Part II of Module F
   - Including all charge types associated with Energy Market Coordination Service under Part III of Module F
2. Day-Ahead Energy Market
   - Including all charge types associated with Congestion Management Service under Part III of Module F
3. Virtual Transactions
   - Including all charge types associated with Energy Market Coordination Service under Part III of Module F
4. FTR Auction activity
   - Including all charge types associated with Energy Market Coordination Service under Part III of Module F
5. FTR portfolio
   - Including all charge types associated with Energy Market Coordination Service under Part III of Module F
6. Congestion and losses
   - Including all charge types associated with Energy Market Coordination Service under Part III of Module F
7. Transmission Service
   - Including Schedule 31 charges associated with Reliability Coordination Service under Part I of Module F

In general, the calculation of potential exposure to non-payment within each service category is based on three exposure components:

1. Invoiced but not paid;
2. Measured but not invoiced, where measured means the settlement systems of the Midwest ISO have computed the charges and credits for all transactions for a given Operating Day; and
3. Estimated for future operating days based on known and/or potential activity.

In the event a Market Participant's Total Potential Exposure exceeds its Total Credit Limit as of the close of business on three (3) consecutive days, then for the next ten (10) days the Market Participant's Total Potential Exposure shall be equal to the sum of: (i) the amount calculated per the formulas in this Section IV; plus (ii) a factor of up to ten (10) times the average amount of the excess exposure over the three (3) consecutive days, if the Transmission Provider determines, after consultation with the Market Participant, that such additional collateral is necessary to reflect the potential exposure associated with the Market Participant's expected market activity.

L - the set of all Congestion and Losses Charge Types that have been settled and/or calculated, but not yet invoiced.

CLEE (Congestion and Losses Estimated Exposure):

CLEE will be the greater of:

(1) The seven day rolling average of daily Congestion and Losses Charges/Credits from previously approved initial Settlements times six (6).

OR

(2) The three hundred sixty five (365) day rolling average of daily Congestion and Losses Charges/Credits from previously approved S7 Settlements times six (6).

7) Transmission Service Potential Exposure

Transmission Service Potential Exposure is calculated per the formula below:

$$\sum TIE + \sum TME$$

Modify formula above to include two new exposure charge types for Reliability Coordination Service (see next sheet).

Where:

TIE (Transmission Invoiced Exposure) = all transmission service charges associated with confirmed Transmission Service reservations from the number of days in the previous month which have been calculated or invoiced but not yet paid.

TME (Transmission Measured Exposure) = all transmission service charges associated with confirmed Transmission Service reservations for:

A. The number of days of the current month which when added to the number of days in the previous month equals 50 Calendar Days if the TIE has not been paid.

OR

B. The number of days in the current month plus the required number of days in the subsequent month to equal 50 Calendar Days if the TIE has been paid.

RCIE (Reliability Coordination Invoiced Exposure) – all Schedule 31 charges associated with Reliability Coordination Service under Part I of Module F that have been measured but not yet paid.

RCEE (Reliability Coordination Estimated Exposure) = all Schedule 31 charges associated with Reliability Coordination Service under Part I of Module F that have been measured but not yet paid.

ATTACHMENT KK-1
Form of Service Agreement for Reliability Coordination Service

1.0 This Service Agreement, dated as of the ___day of ___ , ___ is entered into, by and between the Midwest ISO ("Transmission Provider") and ___________ ____________ ("Reliability Coordination Customer"), (also hereafter referred to as Party or Parties as the context requires).

2.0 The Reliability Coordination Customer has been determined by the Transmission Provider to be eligible for Reliability Coordination Service as set forth in Part I of Module F of the Tariff, and the Transmission Provider agrees to provide service upon the request of an authorized representative of the Reliability Coordination Customer.

3.0 The Reliability Coordination Customer: (i) agrees to supply information as set forth in Section 73 of this Tariff, and such other information, data, and specifications reasonably necessary, in accordance with Good Utility Practice, to permit the Transmission Provider to provide the requested service; (ii) agrees to perform the obligations required of Reliability Coordination Customers set forth in the Tariff; and, (iii) agrees to take and pay for the requested service in accordance with the provisions of the Tariff and this Service Agreement.

4.0 Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, (2) the date on which all required technical data has been received and entered into the Transmission Provider models, or (3) any other date that may be established by the Commission. Service under this Service Agreement shall terminate upon receipt of written notification as required by the Tariff, or on a date mutually agreed upon by the Parties, or as otherwise provided under the Tariff or Commission regulations.

5.0 Any notice required or authorized by this Service Agreement ("Notice") or request made by a Party regarding this Service Agreement shall be in writing. Notice shall be personally delivered, transmitted by facsimile (with receipt verbally or electronically confirmed), emailed, delivered by overnight courier or mailed, postage prepaid, to the other Party at the address designated below. A Party may change its designated address upon Notice to the other Party. If the Reliability Coordination Customer has designated a Contract Manager to receive Notice, the contact information for that person or entity shall also be inserted here:

	Transmission Provider	Reliability Coordination Customer
Title:	General Counsel	
Address:	701 City Center Drive Carmel, IN 46032 Fax: 317-249-5912 Email@	
	Contract Manager:	

5.1 The Reliability Coordination Customer's designated Contract Manager shall have the following responsibilities, as mutually agreed to by the Parties:

6.0 The Tariff is incorporated herein and made a part hereof.

7.0 Description of Reliability Coordination Customer Transmission Facilities that are within the NERC definition of Bulk Electric System and that will be monitored by the Transmission Provider:

[Attach a separate sheet listing all facilities to be covered by this Service Agreement]

8.0 The Reliability Coordination Customer has determined that the following Reliability Coordination Customer Transmission Facilities are subject to the following contractual commitments that may limit the Reliability Coordination Customer's ability to reconfigure its Reliability Coordination Customer Transmission Facilities when directed to do so by the Transmission Provider: [Describe the transmission facility and the nature of contractual limitation]

9.0 The following contractual commitments, laws or environmental restrictions may limit the Reliability Coordination Customer's ability to redispatch generation when directed to do so by the Transmission Provider: [Describe the facility and the nature of the limitation known to the Reliability Coordination Customer]

10.0 Representations and Warranties. Each Party represents and warrants to the other that, as of the date it executes this Service Agreement:

10.1 The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

10.2 The execution and delivery by the Party of this Service Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict, based on present knowledge and information, with any applicable law or with any other agreement binding upon the Party; this Service Agreement has been duly executed and delivered by the Party, and, upon receipt of any necessary regulatory approvals, this Service Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity;

10.3 There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder; and

10.4 It is in compliance with all NERC and Regional Entity standards applicable to its operations and facilities.

11. Assignment. Neither Party may assign this Service Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld, except in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. Notwithstanding anything to the contrary herein, the following conditions shall apply to assignment of this Service Agreement by the Reliability Coordination Customer: (1) assignment may be made to only another eligible Reliability Coordination Customer; (2) if any change is requested by the assignee, it may be approved by the Transmission Provider only if such change does not impair reliability; and (3) the assignee must agree to be subject to and bound by all applicable terms and conditions of the Service Agreement and the Tariff. .

12. Third Party Beneficiaries. There are no intended third-party beneficiaries of this Service Agreement. Nothing in this Service Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any person not a Party to this Service Agreement.

13. Entire Agreement. This Service Agreement, which incorporates the Tariff, constitutes the entire understanding and agreement of the Parties, and supersedes any and all previous communications, representations, understandings, and agreements (oral or written) between the Parties with respect to the subject matter hereof. The headings used in this Service Agreement are for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

14. No Joint Venture. Nothing contained in this Service Agreement shall be construed to imply the existence of a joint venture, principal and agent relationship, or employment relationship between the Parties, and no Party shall have any right, power or authority to create any obligation, express or implied, on behalf of the other Party without the express written consent of the other.

15. Governing Law. This Service Agreement, to the extent not subject to the jurisdiction of the FERC, shall be governed by and construed in accordance with applicable State laws.

16. Additional Terms. If the Reliability Coordination Customer is the United States of America or an agency thereof, the terms and conditions found in Section 12B of the Tariff applicable to participation by the United State of America shall be incorporated in this Service Agreement and shall become a part hereof by this reference. If the Reliability Coordination Customer is a public-power entity, the terms and conditions found in Section 12E of the Tariff applicable to participation by public power entities shall be incorporated in this Service Agreement and shall become a part hereof by this reference.

17. No Waiver of Jurisdictional Immunity. If the Reliability Coordination Customer is not subject to the jurisdiction of the FERC as a "public utility" under the Federal Power Act, the Reliability Coordination Customer shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over the Reliability Coordination Customer. Nothing in this Service Agreement waives any objection to, or otherwise constitutes a consent to, the jurisdiction by FERC over the Reliability Coordination Customer or its transmission service, facilities and rates.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider	Reliability Coordination Customer
By: ____________	By: ____________
Name: ____________	Name: ____________
Title: ____________	Title: ____________
Date: ____________	Date: ____________

ATTACHMENT KK-2
Form of Service Agreement Interconnected Operations and Congestion Management Service

1.0 This Service Agreement, dated as of the ___ day of _________, ____ is entered into, by and between the Midwest ISO ("Transmission Provider") and _______________________ ("Congestion Management Customer"), (also hereafter referred to as Party or Parties as the context requires).

2.0 The Congestion Management Customer has been determined by the Transmission Provider to be eligible for Services as set forth in Part II of Module F of the Tariff and the Transmission Provider agrees to provide service upon the request of an authorized representative of the Congestion Management Customer.

3.0 The Congestion Management Customer agrees : (i) to supply information as set forth in Section 80 of the Tariff, and such other information, data, and specifications as the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order to provide the requested service; (ii) to perform the obligations required of Congestion Management Customers under the Tariff; and (iii) to take and pay for the requested service in accordance with the provisions of the Tariff.

4.0 Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, (2) the date on which all required technical data has been received and entered into the Transmission Provider models, or (3) any other date that may be established by the Commission. Service under this Service Agreement shall terminate upon receipt of written notification as required by the Tariff, or on a date mutually agreed upon by the Parties, or as otherwise provided under the Tariff or Commission regulations.

5.0 Any notice required or authorized by this Service Agreement ("Notice") or request made by a Party regarding this Service Agreement shall be in writing. Notice shall be personally delivered, transmitted by facsimile (with receipt verbally or electronically confirmed), emailed, delivered by overnight courier or mailed, postage prepaid, to the other Party at the address designated below. A Party may change its designated address upon Notice to the other Party. If the Congestion Management Customer has designated a Contract Manager to receive Notice, the contact information for that person or entity shall also be inserted here:

Transmission Provider		Congestion Management Customer
Title:	General Counsel	____________
Address:	701 City Center Drive	____________
	Carmel, IN 46032	____________
	Fax: 317-249-5912	
	Email@	
	Contract Manager:	____________
		____________

6.0 The Tariff is incorporated herein and made a part hereof.

7.0 Description of the Congestion Management Customer's transmission facilities that are within the NERC definition of Bulk Electric System, and all Flowgates that are Coordinated Flowgates, and Reciprocal Coordinated Flowgates under the Congestion Management Customer's control:

[Attach a separate sheet listing all facilities and Flowgates to be covered by this Service Agreement]

____
____
____
____
____
____

8.0 The Transmission Provider and the Congestion Management Customer have determined that the initial list of Designated Flowgates, as defined in Section 83.2 of the Tariff, shall be the following:

____
____
____
____
____
____

9.0 The Transmission Provider and the Congestion Management Customer have determined that the initial list of generators that are capable of relieving congestion, as defined in Section 83.2 of the Tariff, shall be the following:

10.0 Representations and Warranties. Each Party represents and warrants to the other that, as of the date it executes this Service Agreement:

10.1 The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

10.2 The execution and delivery by the Party of this Service Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not, based on present knowledge and information, conflict with any applicable law or with any other agreement binding upon the Party; this Service Agreement has been duly executed and delivered by the Party, and, upon receipt of any necessary regulatory approvals, this Service Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

10.3 There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder; and

10.4 It is in compliance with all NERC and Regional Entity standards applicable to its operations and facilities.

11. Assignment. Neither Party may assign this Service Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld, except in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. Notwithstanding anything to the contrary herein, the following conditions shall apply to assignment of this Service Agreement by the Congestion Management Customer: (1) assignment may be made to only another eligible Congestion Management Customer; (2) if any change is requested by the assignee, it may be approved by the Transmission Provider only if such change does not impair reliability; and (3) the assignee must agree to be subject to and bound by all applicable terms and conditions of the Service Agreement and the Tariff.

12. Third Party Beneficiaries. There are no intended third-party beneficiaries of this Service Agreement. Nothing in this Service Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any person not a Party to this Service Agreement.

13. Entire Agreement. This Service Agreement, which incorporates the Tariff, constitutes the entire understanding and agreement of the Parties, and supersedes any and all previous communications, representations, understandings, and agreements (oral or written) between the Parties with respect to the subject matter hereof. The headings used in this Service Agreement are for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

14. No Joint Venture. Nothing contained in this Service Agreement shall be construed to imply the existence of a joint venture, principal and agent relationship, or employment relationship between the Parties, and no Party shall have any right, power or authority to create any obligation, express or implied, on behalf of the other Party without the express written consent of the other.

15. Governing Law. This Service Agreement, to the extent not subject to the jurisdiction of the FERC, shall be governed by and construed in accordance with applicable State laws.

16. Additional Terms. If the Congestion Management Customer is the United States of America or an agency thereof, the terms and conditions found in Section 12B of the Tariff shall be incorporated in this Service Agreement and shall become a part hereof by this reference. If the Congestion Management Customer is a public-power entity, the terms and conditions found in Section 12E of the Tariff applicable to participation by public power entities shall be incorporated in this Service Agreement and shall become a part hereof by this reference.

17. No Waiver of Jurisdictional Immunity. If the Congestion Management Customer is not subject to the jurisdiction of the FERC as a "public utility" under the Federal Power Act, the Congestion Management Customer shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over the Congestion Management Customer. Nothing in this Service Agreement waives any objection to, or otherwise constitutes a consent to, the jurisdiction by FERC over the Congestion Management Customer or its transmission service, facilities and rates.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider		Congestion Management Customer	
By:	______	By:	______
Name:	______		______
Title:	______		______
Date:	______	Date:	______

ATTACHMENT KK-3
Form of Service Agreement for Market Coordination Service

1.0 This Service Agreement, dated as of the ___day of _________, ___ is entered into, by and between the Midwest ISO ("Transmission Provider") and _______________ ("Market Coordination Customer"), (also hereafter referred to as Party or Parties as the context requires).

2.0 The Market Coordination Customer has been determined by the Transmission Provider to be eligible for Market Coordination Service as set forth in Part III of Module F of the Tariff, and the Transmission Provider agrees to provide the services upon the request of an authorized representative of the Market Coordination Customer.

3.0 The Market Coordination Customer agrees: (i) to supply information as set forth in Section 91 of the Tariff and such other information, data, and specifications as the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order to provide the requested service; (ii) to perform the obligations required of Market Coordination Customers under the Tariff; and, (iii) to take and pay for the requested service in accordance with the provisions of the Tariff.

4.0 Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, or (2) the date on which all required transmission facilities, loads and resources for which the Market Coordination Customer is responsible have been received and entered into the Transmission Provider's Network Model and the Transmission Provider's Commercial Model, or (3) any other date that may be established by the Commission. Service under this agreement shall terminate upon receipt of written notification as required by the Tariff, or on a date mutually agreed upon by the Parties, or as otherwise may be provided under the Tariff or Commission regulations.

5.0 Any notice required or authorized by this Service Agreement ("Notice") or request made by a Party regarding this Service Agreement shall be in writing. Notice shall be personally delivered, transmitted by facsimile (with receipt verbally or electronically confirmed), emailed, delivered by overnight courier or mailed, postage prepaid, to the other Party at the address designated below. A Party may change its designated address upon Notice to the other Party. If the Market Coordination Customer has designated a Contract Manager to receive Notice, the contact information for that person or entity shall also be inserted here:

Transmission Provider		Market Coordination Customer
Title:	General Counsel	______
Address:	701 City Center Drive	______
	Carmel, IN 46032	______
	Fax: 317-249-5912	______
	Email@	
	Contract Manager:	______
		______

6.0 The Tariff is incorporated herein and made a part hereof.

7.0 Description of the Market Coordination Customer Transmission Facilities:

[On the attached sheet list all facilities to be covered by this Service Agreement and identify which services are being elected for each facility.]

8.0 The ATC/AFC/TTC methodology to be used to coordinate transmission service between the Tariff and the Market Coordination Customer's transmission tariff shall be as set forth in Attachment A to this Service Agreement.

9.0 Representations and Warranties. Each Party represents and warrants to the other that, as of the date it executes this Service Agreement:

9.1 The Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

9.2 The execution and delivery by the Party of this Service Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict, based on present knowledge and information, with any applicable law or with any other agreement binding upon the Party; this Service Agreement has been duly executed and delivered by the Party, and, upon receipt of any necessary regulatory approvals, this Service Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity;

9.3 There are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder; and

9.4 It is in compliance with all NERC and Regional Entity standards applicable to its operations and facilities.

10. Assignment. Neither Party may assign this Service Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld, except in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. Notwithstanding anything to the contrary herein, the following conditions shall apply to assignment of this Service Agreement by the Market Coordination Customer: (1) assignment may be made to only another eligible Market Coordination Customer; (2) if any change is requested by the assignee, it may be approved by the Transmission Provider only if such change does not impair reliability; and (3) the assignee must agree to be subject to and bound by all applicable terms and conditions of the Service Agreement and the Tariff. .

11. Third Party Beneficiaries. There are no intended third-party beneficiaries of this Service Agreement. Nothing in this Service Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any person not a Party to this Service Agreement.

12. Entire Agreement. This Service Agreement, which incorporates the Tariff, constitutes the entire understanding and agreement of the Parties, and supersedes any and all previous communications, representations, understandings, and agreements (oral or written) between the Parties with respect to the subject matter hereof. The headings used in this Service Agreement are for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

13. No Joint Venture. Nothing contained in this Service Agreement shall be construed to imply the existence of a joint venture, principal and agent relationship, or employment relationship between the Parties, and no Party shall have any right, power or authority to create any obligation, express or implied, on behalf of the other Party without the express written consent of the other.

14. Governing Law. This Service Agreement, to the extent not subject to the jurisdiction of the FERC, shall be governed by and construed in accordance with applicable State laws.

15. Additional Terms. If the Market Coordination Customer is the United States of America or an agency thereof, the terms and conditions found in Section 12B of the Tariff shall be incorporated in this Service Agreement and shall become a part hereof by this reference. If the Market Coordination Customer is a public-power entity, the terms and conditions found in Section 12E of the Tariff applicable to participation by public power entities shall be incorporated in this Service Agreement and shall become a part hereof by this reference.

16. No Waiver of Jurisdictional Immunity. If the Market Coordination Customer is not subject to the jurisdiction of the FERC as a "public utility" under the Federal Power Act, the Market Coordination Customer shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over the Market Coordination Customer. Nothing in this Service Agreement waives any objection to, or otherwise constitutes a consent to, the jurisdiction by FERC over the Market Coordination Customer or its transmission service, facilities and rates.

17. Tax-Exempt Financing. If the Market Coordination Customer is an entity to which Section 12E of the Tariff applies and has financed its generation and transmission facilities, and may in the future finance upgrades, improvements and additions to its generation and transmission facilities, with the proceeds of debt, the interest on which is excluded from gross income for Federal and State income tax purposes, then as a condition to this Service Agreement becoming effective, the Market Coordination Customer shall obtain and deliver to the Transmission Provider an opinion of a nationally recognized bond counsel, or a ruling of the Internal Revenue Service ("IRS") that the obligations of performance, as set forth in Module F of the Tariff, as of the date of such opinion or ruling, would not adversely affect such exclusion from gross income or otherwise impair the tax exempt status of such debt. Notwithstanding any other provision of this Service Agreement or the Tariff, the Market Coordination Customer shall not be required to perform or receive performance under this Service Agreement or Module F of the Tariff if, in a subsequent opinion of a nationally recognized bond counsel or a ruling of the IRS, it is determined that such performance or receipt of performance would adversely affect the exclusion from gross income for Federal or State income tax purposes of interest paid or to be paid on any debt issued or to be issued by or for the benefit of the Market Coordination Customer. In such circumstances the parties to this Service Agreement may initiate the procedures set forth in Section 12E of the Tariff, or the Transmission Provider may immediately terminate this Service Agreement, or the Market Coordination Customer may immediately terminate this Service Agreement, subject to the requirements of Sections 94.3 to 94.3.5, Section 97.2 and Section 97.3 of the Tariff.

18. Bond Covenant and Financing Agreement Obligations. Nothing in Module F of the Tariff or this Service Agreement, nor anything arising from the Market Coordination Customer's obligations and performance thereunder, shall affect or require the Market Coordination Customer to which Section 12E of the Tariff applies to take or refrain from taking any action that would affect the rights and obligations or enforceability of the Market Coordination Customer's bond resolutions and financing agreements. The Market Coordination Customer shall determine, in accordance with advice and opinions from a nationally recognized bond counsel, what actions, conduct and performance it is permitted to or must take under its bond resolutions and financing agreements. If, at any time, the Market Coordination Customer's performance or receipt of performance under this Service Agreement or Module F of the Tariff would impair or adversely affect the rights, obligations or enforceability of the Market Coordination Customer's bond resolutions and financing agreements, then the Market Coordination Customer shall immediately notify the Transmission Provider of this fact and the parties to this Service Agreement may initiate the procedures set forth in Section 12 E of the Tariff, or the Transmission Provider may immediately terminate this Service Agreement, or the Market Coordination Customer may immediately terminate this Service Agreement, subject to the requirements of Sections 94.3 to 94.3.5, Section 97.2 and Section 97.3 of the Tariff.

19. Transition Period Charges. Based upon the Market Coordination Customer's historic usage of the Transmission System during the twelve months period preceding the effective date of Part III of Module F of the Tariff, the charge for Market Integration Transmission Service as set forth in Schedule 32 shall be $_________ per month for the remainder of the Transition Period.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider	Market Coordination Customer
By: ____________________	By: ____________________
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________
Date: ____________________	Date: ____________________

Congestion Management Process (CMP) MASTER

Baseline
Version 1.1
November 30, 2007

Executive Summary

This Congestion Management Process 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 Market Flows upon those Flowgates.*
- *Market-Based Operating Entities will determine Firm Market Flows and constrain their operations to limit Firm Market Flows on the Coordinated Flowgates to no more than the calculated Firm Flow Limit established in the analysis.*
- *In real-time, Market-Based Operating Entities will calculate and monitor one-hour ahead projected and actual flows.*
- *Market-Based Operating Entities will post to the IDC the actual and the one-hour ahead projected market flow, consisting of the Firm Market Flow and the additional Non-Firm Market Flow, for both internal and external Coordinated Flowgates.*

- *Market-Based Operating Entities will provide to the IDC detailed representation of their marginal units, so that the IDC can continue to effectively compute the effects of all tagged transactions regardless of the size of the market area. These tagged transactions will include 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 Market Flows exceed the Firm Flow Limits, Market-Based Operating Entities will redispatch in order to provide the required megawatt (MW) relief, per the IDC congestion management report.*
- *When there is a TLR 5a or 5b, all Transmission Providers will curtail or redispatch their respective systems to provide their shares of Network and Native Load (NNL) reductions as directed by the IDC.*
- *Because the IDC will have the real-time/one-hour ahead projected flows throughout the Market-Based Operating Entity's system (as represented by the impacts upon various Coordinated Flowgates), the effectiveness of the IDC will be greatly enhanced.*
- *The 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 the Midwest ISO
- MAPPCOR and the Midwest ISO
- The Midwest ISO and PJM
- The Midwest ISO, PJM and TVA
- The Midwest ISO and 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 CMPCmember 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."

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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 congestion management process (CMP) offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the NERC 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

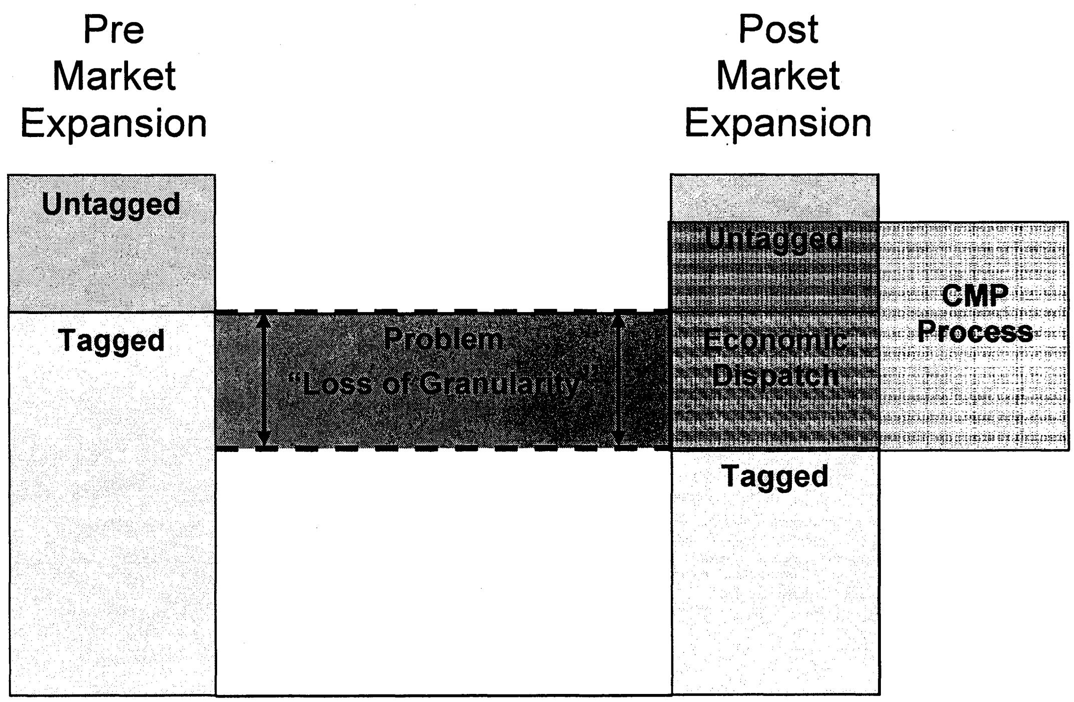
The processes set forth in this document were based on the following assumptions:

1. Point-to-point schedules sinking in, sourcing from, or passing through a Market-Based Operating Entity will be tagged.
2. The IDC or a similar repository of schedules is needed at the Interconnection's current state and for the foreseeable future.
3. The Market-Based Operating Entity can compute the impacts of the untagged market dispatch on the Flowgates as currently required by the IDC.
4. The Market-Based 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.
5. 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.
6. The IDC has been modified to accept the calculated values of the impact of real-time generation in order to determine which schedules require curtailment in conjunction with the required Market-Based Operating Entity's redispatch.
7. The IDC can calculate the total amount of MW relief required by the Market-Based Operating Entity (schedule curtailments required plus the relief provided by redispatch).

Section 2 - 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.



Market Flows are defined as 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. (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).

Market Flows can be divided into Firm Market Flows and Non-Firm Market Flows. Firm Market 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 Market 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 four studies to determine which Flowgates the Operating Entity will monitor and help control. A Flowgate passing any one of these studies will be considered a Coordinated Flowgate. Only AFC Flowgates will be eligible for consideration as Coordinated Flowgates. A Flowgate must have AFCs computed and these AFCs must be used to sell Transmission Service in order to be a Coordinated Flowgate.

An Operating Entity may also specify additional Flowgates that have not passed any of the four studies to be Coordinated Flowgates. For Flowgates on which the Operating Entity expects to utilize the TLR process to protect system reliability, such specification is required. For a list of Coordinated Flowgates between Reciprocal Entities, please 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 four Flowgate studies, a 5% threshold will be applied on an absolute basis without regard to the positive or negative sign of the impact. Use of a 5% threshold in the studies may not capture all Flowgates that experience a significant impact due to market operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC and/or NAESB implements the use of a lower threshold in the TLR process.

3.2.1 Flowgate Studies

Study 1) – IDC Base Case

(using the IDC tool)
This is a one time study done before Control Area consolidation. The IDC can provide a list of Flowgates for any user-specified Control Area whose GLDF (Generator to Load Distribution Factor (NNL)) impact is 5% or greater. The Operating Entity will use the IDC capabilities to develop a preliminary set of Flowgates. This list will contain Flowgates that are impacted by 5% or greater by the Control Areas that will be joining the Operating Entity as Control Zones/areas. OTDF Flowgates will be analyzed with the contingent element out of service. Using the historic Control Area representation in the IDC (i.e., pre-Operating Entity expansion), if any one generator has a GLDF (Generator to Load Distribution Factor) greater than 5% as determined by the IDC, this Flowgate will be considered a Coordinated Flowgate.

Study 2) – IDC PSS/E Base Case

(no transmission outages - offline study)
For those situations where one or more CAs are being, or have been incorporated into an Operating Entity's footprint after the freeze date, there will be a generator analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. In order to confirm the IDC analysis, and to provide a better confidence that the Operating Entity has effectively captured the subset of Flowgates upon which its generators have a significant impact, an offline study utilizing MUST capabilities will be conducted. The Operating Entity will perform off-line studies (using the IDC PSS/E base case) to confirm the IDC analysis. Study 1 and 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

(transmission outage - offline study)
For those situations where one or more CAs are being, or have been incorporated into an Operating Entity's footprint after the freeze date, there will be a Flowgate analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity, in consultation with affected operating authorities, will perform a prior outage analysis, including both internal and external outages. The Flowgates determined using Study 2 or 4 that have a 3% to 5% distribution factor will be analyzed against prior outage conditions. This study will be performed offline utilizing MUST capabilities. If any Flowgates with a 3% to 5% distribution factor from Study 2 or 4 are impacted by 5% or more from a prior outage condition (Line Outage Distribution Factor LODF) from this method, the Flowgate will be added to the list of Coordinated Flowgates.

Study 4) – Control Area to Control Area

For those situations where one or more CAs are being, or have been incorporated into an Operating Entity's footprint after the freeze date, there will be a Flowgate analysis performed to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity will analyze transactions between each new CA and the existing market, as well as between each CA/CA permutation (if more than one CA is moving into the footprint). OTDF Flowgates will be analyzed with the contingent element out of service. This study will use Transfer Distribution Factors (TDFs) from the IDC and offline studies utilizing MUST capabilities. Flowgates that are impacted by greater than 5% as determined by the IDC 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 four studies described above; in addition to any other studies they believe illustrate the validity of their request. The other Reciprocal Entity will review the studies and determine if they appear to support the request of the Reciprocal Entity conducting the study. If they do, the Flowgate will be added to the list of Coordinated Flowgates.
- If, following evaluation of the supplied studies, any Reciprocal Entity still disputes another Reciprocal Entity's request, the Reciprocal Entity will submit a formal request to the NERC Operations Reliability Subcommittee (ORS) asking for further review of the situation. The 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 in its stakeholder processes 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

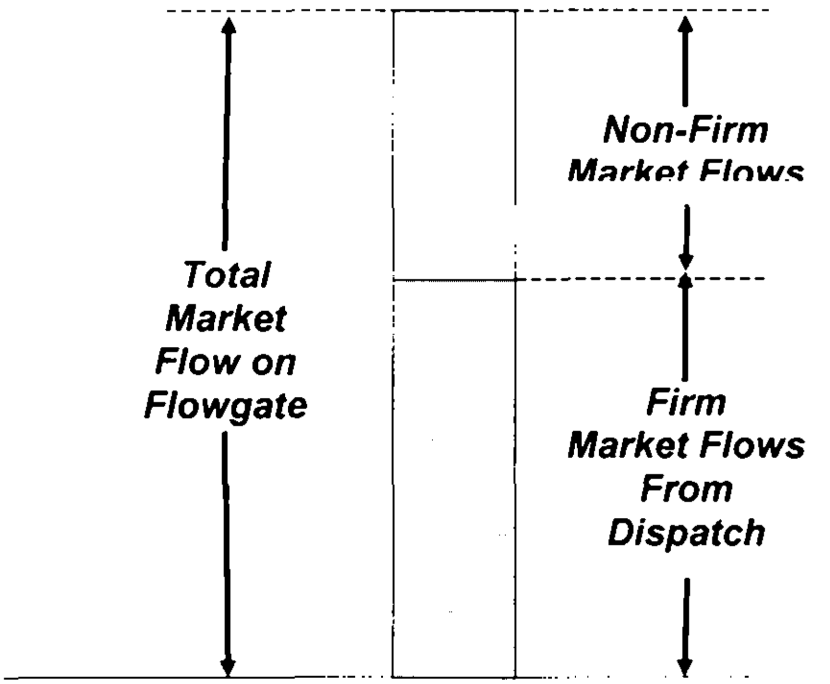
The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then on a periodic basis, as described in Appendix C.

3.2.5 Dynamic Creation of Coordinated Flowgates

For temporary Flowgates developed "on the fly," the IDC will utilize the current IDC methodology for determining NNL contribution until the Market-Based Operating Entity has begun reporting data for the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will 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 four studies detailed earlier in this document and determine the Flowgate's relationship with the Market-Based Operating Entity's dispatch. For internal Flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Market Flows; during a TLR 5, the IDC will request NNL relief in the same manner as today. Alternatively, for internal and external Flowgates, an Operating Entity may utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary Flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary Flowgate's monitored element and with the same contingent element. If the Flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. 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.

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] This methodology is presently used in the IDC to determine NNL contributions.

Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific Flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (e.g. the terminal bus of each generator) while the LSFs are defined as a general scaling of the market area's load. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific Flowgate is the product of the generator's GLDF multiplied by the actual output (in megawatts) of that generator. The total Market Flow on a specific Flowgate is 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 the entire RTO footprint, as in the following illustration, or it may be 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. In the latter case, the total market flow of an RTO shall be the sum of the flows from and between such market areas.

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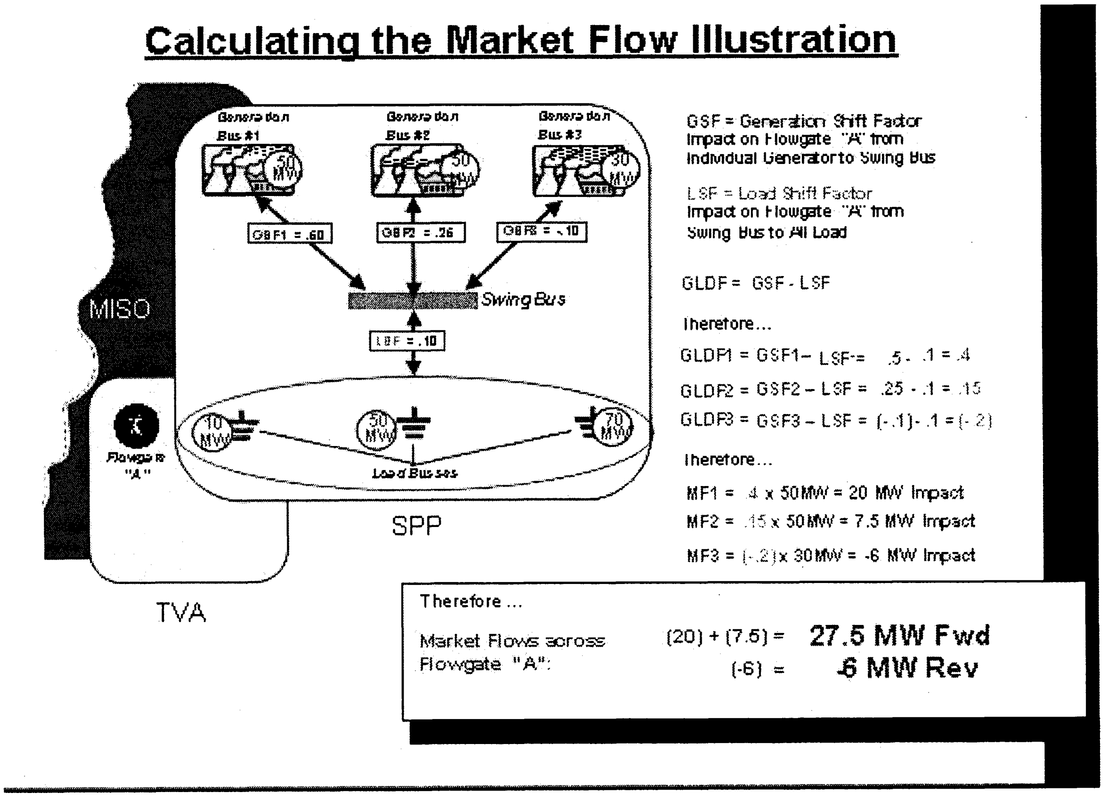
[1] "Parallel Flow Calculation Procedure Reference Document," NERC Operating Manual. 11 Feb. 2003. <http://www.nerc.com/~oc/opermanl.html>



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

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF greater than 5% are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The Market Flow calculations will use all flows, in both directions, down to a 3% threshold (this Market Flow threshold is subject to the outcome of the NERC approved TLR procedures 12 month field test and the specific terms and conditions and effective date on which each Market-Based Operating Entity will or has started the 12 month field test). 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.

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

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

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

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

Below is a summary of the calculations discussed above.

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

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

and,

GLDF is the Generator to Load Distribution Factor

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

Participation Percent is the share of the unit participating in the Market-Based Operating Entity's market

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

The real-time and 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: