Joint Operating Agreement
Between the
Midwest Independent Transmission System Operator, Inc.
And
PJM Interconnection, L.L.C.

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ARTICLE I
RECITALS

This Joint Operating Agreement ("Agreement") dated this ___day of December, 2003, by and between PJM Interconnection, L.L.C. ("PJM") a Delaware limited liability company having a place of business at 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403, and the Midwest Independent Transmission System Operator, Inc. ("MIDWEST ISO"), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032.

WHEREAS, PJM is the regional transmission organization that provides operating and reliability functions in portions of the mid-Atlantic and Midwest States. PJM also administers an open access tariff for transmission and related services on its grid, and independently operates markets for day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, the MIDWEST ISO is the regional transmission organization that provides operating and reliability functions in portions of the Midwest States and Canadian Providences. The MIDWEST ISO administers an open access tariff for transmission and related services on its grid, and is developing processes and systems to operate markets to facilitate trading of day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, the Federal Energy Regulatory Commission has ordered each regional transmission organization to develop mechanisms to address inter-regional coordination;

WHEREAS, on February 12, 2003, the Parties entered into the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market ("Joint and Common Market Agreement"), which provides for the establishment of an Inter-RTO Steering Committee to facilitate development of the Joint and Common Market and resolution of seams issues between the Parties;

WHEREAS, certain other electric utilities will be integrated into the systems and markets PJM administers and controls, and it is recognized that such integration may result in changed flows on the systems of PJM and the MIDWEST ISO as they exist prior to such integration;

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

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, including the Parties' mutual reliance upon the covenants contained herein, the receipt of which hereby is acknowledged, PJM and the MIDWEST ISO hereby agree as follows:

ARTICLE II
ABBREVIATIONS, ACRONYMS AND DEFINITIONS

2.1 Abbreviations and Acronyms.

2.1.1 "ATC" shall mean Available Transfer Capability.

2.1.2 "AFC" shall mean Available Flowgate Capability.

2.1.3 "CBM" shall mean Capacity Benefit Margin.

2.1.4 "CIM" shall mean Common Information Model.

2.1.5 "EFOR" shall mean Equivalent Forced Outage Rate.

2.1.6 "EMS" shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their Regions.

2.1.7 "FERC" shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

2.1.8 "FTP" shall mean the standardized file transfer protocol for data exchange.

2.1.9 "FTR" shall mean financial transmission rights.

2.1.10 "GCA" shall mean the generation control area.

2.1.11 "ICCP", "ISN" and "ICCP/ISN" shall mean those common communication protocols adopted to standardize information exchange.

2.1.12 "IDC" shall mean the NERC Interchange Distribution Calculator used for tracking reliability data.

2.1.13 "IDCWG" shall mean the NERC Working Group established to provide advice on the IDC.

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

2.1.15 "JRPC" shall mean the Joint RTO Planning Committee.

2.1.16 "LCA" shall mean the Load Control Area.

2.1.17 "MMWG" shall mean the NERC working group that is charged with multi-regional modeling.

2.1.18 "MVAR" shall mean megavolt amp of reactive power.

2.1.19 "MW" shall mean megawatt of power.

2.1.20 "MWh" shall mean megawatt hour of energy.

2.1.21 "NERC" shall mean the North American Electricity Reliability Council or its successor organization.

2.1.22 "NNL" shall mean network and native load calculation.

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

2.1.24 "OATi" shall mean the entity that has been retained by NERC, or successor organization, to maintain the IDC system.

2.1.25 "OATT" shall mean the applicable open access transmission tariff.

2.1.26 "PMAX" shall mean the maximum generator real power output reported in MWs on a seasonal basis.

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

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

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

2.1.30 "RTO" shall mean regional transmission organization.

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

2.1.32 "TLR" shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

2.1.33 "TRM" shall mean Transmission Reliability Margin.

2.1.34 "TTC" shall mean Total Transfer Capability.

2.2 **Definitions.** Any undefined, capitalized terms used in this Agreement shall have the meaning given under industry custom and, where applicable, in accordance with good utility practices.

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

2.2.2 "Affected System" shall have the meaning given in Section 9.4.

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

2.2.4 "Available Flowgate Capability" shall have the meaning stated in Section 5.1.7.

2.2.5 "Available Flowgate Rating" shall have the meaning stated in Section 5.1.8.

2.2.6 "Available Transfer Capability" shall have the meaning stated in Section 5.1.

2.2.7 "Commonwealth Edison" shall mean the Commonwealth Edison Company.

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

2.2.9 "Congestion Management White Paper" means that document entitled, "Managing Congestion to Address Seams for Congestion Management Coordination," as it exists on the Effective Date and as it may be amended or revised from time to time. The Congestion Management White Paper is incorporated herein as Appendix A to this Agreement.

2.2.10 "Control Area(s)" shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

2.2.11 "Coordinated Flowgates" shall mean those flowgates that are affected by the transmission of energy by a Party. A Coordinated Flowgate may be under the operational control of one of the Parties, or may be under the operational control of a third party.

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

2.2.13 "Coordinated System Plan" shall have the meaning stated in Section 9.3.5.

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

2.2.15 "Effective Date" shall have the meaning stated in Section 12.1.

2.2.16 "Hold Harmless Issues" shall have the meaning given in Section 4.3.

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

2.2.18 "Interconnected Reliability Limit" or "IRL" shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages.

2.2.19 "Inter-regional Planning Stakeholder Advisory Committee or "IPSAC" shall have the meaning given under Section 9.1.2.

2.2.20 **"**Inter-RTO Steering Committee" or "ISC" shall have the meaning given in the Joint and Common Market Agreement.

2.2.21 "Joint and Common Market" shall mean, in phased development, (1) implementation of a single market portal that would allow customers to seamlessly engage in "one stop" shopping in the MIDWEST ISO and PJM markets and where the Parties will implement integrated dispatch protocols and market to market integrated congestion management; and (2) implementation of a single market covering both the MIDWEST ISO and PJM footprints in which the market products offered by each Party would converge into single products under a single tariff.

2.2.22 "Joint and Common Market Agreement" shall mean the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market, executed by the Parties on or about February 12, 2003.

2.2.23 "The Joint RTO Planning Committee" or "JRPC" shall be formed and exist under Section 9.1.1.

2.2.24 "Locational Marginal Price" or "LMP" shall mean the market clearing price for energy at a given location in a Party's Region, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

2.2.25 "LMP Contingency Processor" shall mean that Locational Marginal Price pricing computer program referred to in Section 11.2.1.

2.2.26 "Market to Market" shall have the meaning referred to in Sections 3.2 and 3.3.2.

2.2.27 "Market to Non-Market" shall have the meaning referred to in Sections 3.2 and 3.3.1.

2.2.28 "Market-Based Operating Entity" shall mean an operating entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.29 "Market Flows" shall mean all flows through a flowgate resulting from a Market-Based Operating Entity's dispatch subject to the control of either Party, except flows that are externally tagged.

2.2.30 "MIDWEST ISO" has the meaning stated in the preamble of this Agreement.

2.2.31 "NNL" shall mean network and native load.

2.2.32 "Network Upgrades" shall mean those facilities located beyond the point of interconnection of the generating facility to the transmission grid.

2.2.33 "Northern Illinois Control Area" shall mean, as of the date of this Agreement, control areas of the Commonwealth Edison electrical region, including generator-only control areas.

2.2.34 "Notice" shall have the meaning stated in Section 18.10.

2.2.35 "Outages" shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or the MIDWEST ISO, as described in Article VII of this Agreement.

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

2.2.37 "PJM" has the meaning stated in the preamble of this Agreement.

2.2.38 "Reciprocal Coordinated Flowgates" or "RCFs" shall mean flowgates that are Coordinated Flowgates of both Parties.

2.2.39 **"**Reciprocating Entity(ies)" shall mean an entity that coordinates the forward-looking management of flowgate capacity.

2.2.40 **"**RCF Base Usage" shall mean the long-term firm and network service usage of RCFs.

2.2.41 "Region" shall mean the Control Areas and transmission facilities with respect to which a Party serves as RTO or Reliability Coordinator under NERC policies and procedures.

2.2.42 "Reliability Coordinator" or "RC" shall mean, with respect to a Control Area, an entity approved by NERC to be responsible for reliability for one or more Control Areas, and which has undertaken such responsibility for the applicable Control Area.

2.2.43 "SCADA Data" shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC policies and procedures.

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

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

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

2.2.47 "Unit Dispatch Systems" or "UDS" shall mean those dispatch systems utilized by the Parties to dispatch generation units by calculating the most economic solution while simultaneously ensuring that each of the boundary constraints is resolved reliably.

2.3 Rules of Construction.

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

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

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

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

2.3.5 NERC Policies and Procedures. All activities under this Agreement will meet or exceed the applicable NERC policies or procedures as revised from time to time.

2.3.6 Congestion Management White Paper. The Congestion Management White Paper is hereby incorporated into this Agreement and in the event there is a conflict between this Agreement and the Congestion Management White Paper, the Congestion Management White Paper prevails. The Congestion Management White Paper may be amended from time to time upon agreement of the Parties. Any disputes arising under the Congestion Management White Paper are subject to the dispute resolution provisions contained in Section 14.2 of this Agreement.

2.3.7 Scope of Application. Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Control Area for which it serves as RTO and, in addition, each Control Area for which it serves as Reliability Coordinator.

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

3.1 **Ongoing Review and Revisions.** The Parties have agreed to the coordination and exchange of data and information under this Agreement to enhance system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to these systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement, including changes to the boundaries of a Party in its capacity as an RTO, changes to the boundaries of, or identities of, Control Areas for which a Party serves as Reliability Coordinator, changes in response to findings and recommendations of the United States Department of Energy or NERC concerning the outage of August 14, 2003, and changes upon the commencement of Phase 2, Market to Market implementation. The Parties agree that the objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

3.2 **Definitions of Phases and Applicable Time Periods.** The Parties' coordination and exchange of data and information shall occur in two (2) phases, except as otherwise provided in Section 3.2.1. Phase 1, "Market to Non-Market," shall commence upon the later of the Effective Date or the initiation of an LMP-based market within a PJM Control Area or a MIDWEST ISO Control Area, where such a market did not exist prior to the Effective Date and shall end when all PJM and MIDWEST ISO Control Areas on the interfaces between PJM and the MIDWEST ISO have been included in LMP-based markets. Phase 2, "Market to Market," shall commence when adjacent PJM and MIDWEST ISO Control Areas on the interfaces between PJM and the MIDWEST ISO are included in LMP-based markets and such commencement shall be with respect only to Control Areas that are included in LMP-based markets, provided, that no such additional LMP-based market shall be initiated in the PJM markets prior to the commencement of Phase 1. Phase 2 continues throughout the term of this Agreement, subject to Section 3.3.2.

3.2.1 Limited Earlier Implementation. In order to enhance the reliability of their respective systems, and notwithstanding any other provision of this Agreement, upon mutual execution of this Agreement, the Parties shall commence good faith efforts to implement the elements specified in Sections 3.3.1 (a), (b), (d), (e), (f), (g), (i), (l), and (m).

3.3 Elements of Phase 1 and Phase 2.

3.3.1 Phase 1. Phase 1 shall consist of the elements specified in this Section 3.3.1. Upon the initiation of Phase 1 (or prior thereto pursuant to Section 3.2.1), the Parties shall commence full performance of (a), (b), (c), (d), (e), (f), (g), (i), (j), (k), (m) and (o) and upon the initiation of Phase 1, shall certify to the FERC that they have commenced such full performance. Upon the initiation of Phase 1, the Parties also shall, as applicable, commence or continue performance or development under (h) and (n). Following are the Phase 1 elements:

(a) Exchange of data and information between the MIDWEST ISO and PJM as described in Articles III and IV;

(b) Calculation of TTC/ATC/AFC as described in Article V;

(c) Reciprocal coordination of flowgates as described in Article VI;

(d) Coordination of Outages as described in Article VII;

(e) Joint operation of emergency procedures as described in Article VIII;

(f) Coordinated regional transmission expansion planning as described in Article IX;

(g) Coordinated scheduling checkouts as described in Article X;

(h) Implementation of the NERC-approved Congestion Management White Paper as described in Section 11.1;

(i) Joint reliability coordination (pursuant to NERC policies and procedures) as described in Sections 3.4 and 11.2.13;

(j) Compliance with solutions to the Hold Harmless issues in FERC Docket No. EL02-65-000, *et al*. in accordance with the June 4, 2003 FERC Order, as described in Article XII;

(k) Joint resolution of the issues and recommendations contained in the filing of the MIDWEST ISO Independent Market Monitor and PJM Market Monitor in FERC Docket No. EL03-35-002, as described in Article XIII;

(l) Implementation of the NERC-approved reliability plans of PJM and the MIDWEST ISO applicable to their respective membership configurations as of the Effective Date and as they may change from time to time;

(m) Additions to, or deletions from, the foregoing, to which the Parties may agree from time to time, subject to NERC approval, as set forth above in subsections (h) and (l) of this section, or as ordered by the FERC; and

(n) Preparation and publication for stakeholder review and comment of a "Phase 2 White Paper" containing the procedures and methodologies proposed to implement the elements specified in Section 3.3.2 (a) and (b).

3.3.2 Phase 2. Phase 2, Market to Market, consists of the continuation of all Phase 1 elements (except those that have been completed or due to other circumstances are agreed by the Parties to be impracticable to continue to perform) and, in addition, will consist of the following elements.

(a) Generation redispatch and coordination, as described in Articles VIII and XI (pursuant to NERC policies and procedures);

(b) Consistency in calculating LMP on Coordinated Flowgates as described in Section 11.2.1;

(c) Additions to, or deletions from Items (a) through (n) of Section 3.3.1 and Items (a) and (b) of Section 3.3.2, to which the Parties may agree from time to time, including agreements prior to initiation of Phase 2 and in accordance with Section 3.1, or as ordered by the FERC; and

(d) Implementation of the additional provisions concerning Phase 2, stated in Section 11.2.

3.4 Coordination and Analysis of Pathway from Commonwealth Edison to PJM. Effective upon PJM's inclusion of the Northern Illinois Control Area into the PJM market, transmission service will be provided as set out in Appendix B – PJM Analysis for Pathway Segments of this Agreement.

ARTICLE IV
EXCHANGE OF INFORMATION AND DATA

4.1 Phase 1, Market to Non-Market - Exchange of Operating Data.

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

Requirements: During Phase 1, Market to Non-Market, the Parties will exchange the following types of data and information on a continuous, real-time basis:

(a) Real-Time and Projected Operating Data;

(b) SCADA Data;

(c) EMS Models;

(d) Operations Planning Data; and

(e) Planning Information and Models.

Each Party shall provide the data identified in items (a) through (e) of this Section to the other Party with respect to all entities that participate in PJM's markets during the term of this Agreement, whether or not the entity is a participant as of the Effective Date.

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

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

4.1.1 Real-Time and Projected Operating Data.

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

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

(i) Generation status of the units in each Party's Region;
(ii) Transmission line status;
(iii) Real-time loads;
(iv) Scheduled use of reservations;
(v) TLR information, including calculation of Market Flows;
(vi) Redispatch information, including the next most economical generation block to decrement/increment; and
(vii) Real-time constraints.

(b) Projected operating information consists of:

(i) Unit commitment/merit order;
(ii) Maintenance schedules;
(iii) Forced outage rates;
(iv) Firm purchase and sales;
(v) Independent power producer information including current operating level, projected operating levels, Outage start and end dates;
(vi) The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments; and
(vii) The planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units.

4.1.1.2 The Parties agree that various components of the data exchanged under Section 4.1.1 is Confidential Information and that, in addition to the protections of Confidential Information provided under Section 18.1.2:

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

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

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

4.1.2 Exchange of SCADA Data.

Background: NERC Policy No. 4, Appendix 4B, "Electric System Security Data," describes the types of data that Control Areas are expected to provide, and Reliability Coordinators are expected to share with each other as explained in NERC Policy No. 4B, "Reliability Coordination – Operational Security Information."

Requirements:

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

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

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

(d) The Parties shall exchange SCADA data consisting of:

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

4.1.3 Models.

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

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

4.1.4 Operations Planning Data.

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

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

4.1.4.1 Flowgates.

(a) Flowgate definitions including seasonal TTC, TRM, CBM, and a & b multipliers;

(b) Flowgates to be added on demand;

(c) List of Coordinated Flowgates;

(d) List of flowgates to recognize when selling point-to-point service (if different than list of Coordinated Flowgates); and

(e) Requirements under Section 5.1.7.

4.1.4.2 Transmission Service Reservations.

(a) Daily list of all reservations, hourly increment of new reservations;

(b) List of reservations to exclude; and

(c) Requirements under Sections 5.1.4 and 5.1.5.

4.1.4.3 Available Flowgate Capability Data.

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

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

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

(c) Monthly for months two (2) through eighteen (18), posted at a minimum, twice per month.

4.1.4.4 Load Forecast.

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

(b) Identify the origin of the forecast (*e.g.*, identity of RTO, RC, Control Area, etc.);

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

(d) Identify non-conforming loads;

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

(f) Requirements under Section 5.1.6.

4.1.4.5 Generator Data.

(a) Unit owner, bus location in model;

(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;

(c) Station auxiliaries to extent gross generation has been reported;

(d) Regulated bus, target voltage and actual voltage; and

(e) EFOR.

4.1.4.6 Designated Network Resources.

(a) Network Integration Transmission Service Specifications;

(b) Designated Network Resource information;

(c) Indication of treatment as pseudo tie or dynamic/static schedules;

(d) Rules for sharing output between joint owners; and

(e) Transmission arrangements.

4.1.4.7 Control Area Net Interchange from Reservations and Tags.

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

(b) If tags and reservations can not be used to develop Control Area or zone net interchange, then provide hourly unit commitment information for all generators in the Control Area/zone.

4.1.4.8 Dynamic Schedules.

(a) List of dynamic schedules;

(b) Identification of the dynamic schedules are being used to move load into the Control Area or out of the Control Area;

(c) Identification of marginal generation zones; and

(d) Requirements under Section 5.1.11.

4.1.4.9 Controllable Devices.

(a) Phase shifters;

(b) DC lines; and

(c) Back-to-back AC/DC converters.

4.1.4.10 Generation and Transmission Outages.

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

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

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

4.2 Phase 2, Market to Market - Exchange of Operating Data.

Requirements: Prior to the initiation of Phase 2, Market to Market, the Parties shall confer regarding the need to exchange any information other than that identified for exchange in Phase 1 in Section 4.1, and shall make agreements for exchange of such information during Phase 2 as is necessary to achieve the objectives of this Agreement.

The Parties shall exchange such information as the Market Monitors of PJM and MIDWEST ISO may request, singly or jointly, in order to facilitate monitoring of markets in accordance with the Parties' respective FERC-approved market monitoring plans.

4.3 Cost of Data and Information Exchange.

Requirements: Each Party shall bear its own cost of providing information to the other Party pursuant to Sections 4.1 and 4.2, except to the extent this provision is contrary to (a) any solution the FERC places into effect to the "hold harmless" issues the FERC identified in Alliance Companies, 100 FERC ¶ 61,137 (July 31, 2002); *on rehearing,* 103 FERC ¶ 61,274 (June 4, 2003), and related clarifying orders, the "Hold Harmless Issues," or (b) any agreement or agreements which include the following entities: Michigan and Wisconsin parties (as described in the FERC Order referenced above), Commonwealth Edison, and American Electric Power which the FERC accepts as a solution to the Hold Harmless Issues.

ARTICLE V
TTC/ATC/AFC CALCULATIONS

5.1 TTC/ATC/AFC Protocols - Phase 1, Market to Non-Market.

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

As of the date of this Agreement, the Parties use the NERC SDX System to exchange the planned status of generators rated greater than 150 MW, planned outages of all interconnections and other transmission facilities and peak load forecasts subject to NERC SDX Data Exchange Requirements. This system 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 update frequency of the NERC SDX System is once a day. Reporting of forced outages and update of information on a basis more frequent than once a day will be completed using a separate data exchange system. Use of the NERC SDX, development of a separate data exchange system, and associated commitments under this Agreement, will assure the Parties' ability to make reliable calculations efficiently.

5.1.1 Generation Outage Schedules.

Requirements: Each Party shall provide the other with projected status of generation availability for a minimum of eighteen (18) months or more if available. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each "return date" of a generator from a scheduled or forced outage. At all times, this exchange will include the status of generators rated greater than 150 MW. If the status of a particular generator of equal to or less than 150 MW is used within a Party's TTC/ATC/AFC calculation, the status of this unit shall also be supplied.

5.1.2 Generation Dispatch Order.

Purpose: Dispatch information combined with unit availability information permits each Party to develop a reasonably accurate dispatch for any modeled condition. This methodology is more advantageous than scaling all available generation to meet generation commitments within an area and then increasing all generation uniformly to model an export, or uniformly decreasing all generation to model an import. While excluding nuclear generation or hydro units from this scaling would provide some level of refinement, this approach is inadequate to identify transmission constraints and determine rational TTC/ATC/AFC values.

On the other extreme, although economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment, this level of refinement is generally unnecessary, and the data is likely to be considered confidential by the generation owners, and therefore unavailable. The exchange of typical generation dispatch order or generation participation factors of all units on a Control Area basis and other data under this Agreement will permit each Party to appropriately model future transmission system conditions.

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

5.1.3 Transmission Outage Schedules.

Requirements: Each Party will provide the other Party with the projected status of transmission outage schedules for a minimum of eighteen (18) 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. If the status of a particular transmission facility is critical to the determination of TTC and ATC/AFC of a Party, the status of this facility will also be provided.

5.1.4 Transmission Interchange Schedules and Reservations Schedules.

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

Requirements: Each Party will make available to the other its reservation and interchange schedules, as required to permit accurate calculation of TTC and ATC/AFC values. Due to the high volume of this data, the Parties shall either post this data to a FTP site for downloading by the other Party as required by its own process and schedules, or shall request NERC to modify the IDC to allow for selected interrogation by the Parties.

5.1.5 Reservations.

Purpose: Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of TTC and ATC/AFC for future time periods. Inasmuch as a transmission reservation is a right to use and not an obligation to use the transmission system, there is no certainty that any particular reservation will result in a corresponding interchange schedule. This is especially true considering that the *pro forma* Open Access Transmission Tariff approved by the FERC allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, at a given time, purchased all transmission reservations on a particular source-to-sink path. A further complication is that the duration or firmness of the one portion of the reservation may not be the same as the remaining portion. Since the portions of a source to sink reservation may not be able to be associated prior to scheduling, double counting in the ATC/AFC determination process is a possibility. It is acknowledged that reservations respecting one Party are not required to be incorporated into transmission models developed by the other Party.

Requirements:

(a) Each Party will make available to the other Party, on an FTP site, actual transmission reservation information for integration into each Party's TTC/ATC/AFC determination process.

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

(c) Each Party shall also create, maintain, and exchange a list of reservations from its OASIS that should not be considered in ATC/AFC calculations. If a Party does not include a reservation in its own evaluation, the reservation should be excluded in other the other Party's analysis.

5.1.6 Load Data.

Requirements: The Parties will exchange peak load data for each period in accordance with NERC policies and procedures (*e.g*., daily, weekly, and monthly). Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a Control Area basis by the applicable RTO, RC, Control Area, or other applicable entity, including total distribution forecast by zones.

5.1.7 Calculated Firm and Non-firm Available Flowgate Capability.

Definitions: The AFC is the applicable rating of the applicable flowgate less the projected loading across the applicable flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, including recognition of all roll-over transmission service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

Purpose: Data exchange is required to determine if a transmission service reservation (or interchange schedule) will impact flowgates to an extent greater than the (firm or non-firm) AFC and procedures are necessary to assure that each Party respects the other Party's flowgates as follows.

Requirements:

(a) The Parties will exchange firm and non-firm AFC for all relevant flowgates.

(b) Each Party will accept or reject transmission service requests based upon projected loadings on its own flowgates as well as on RCFs under Article VI.

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

5.1.8 Available Flowgate Rating.

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

Requirements: The Parties will exchange (seasonal, normal and emergency) Available Flowgate Ratings as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system, but the Parties acknowledge that these ratings are currently fairly static values and do not currently require frequent updating. Voltage and stability limits need to be periodically manually updated.

5.1.9 Identification of Flowgates.

Requirements: Each Party shall consider in its TTC and ATC/AFC determination process all flowgates that may initiate a TLR event. As determined in accordance with Section 3 of the Congestion Management White Paper, 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.

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

Requirements:

(a) Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The TTC/ATC/AFC determination processes will require that, when changes occur to the transmission network, models used in the TTC/ATC/AFC calculation be updated as soon as practical. Within sixty (60) days after the Effective Date of this Agreement, a process will be instituted between the Parties to ensure that all significant system changes of a neighbor are incorporated in each Party's TTC/ATC/AFC calculation model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the TTC/ATC/AFC calculation models in a more timely manner.

This type of data change will be similar to the 'New Facilities' Listings usually included in inter-regional reports; however, explicit modeling information will need to be supplied along with the listing. This data exchange will occur no less often than prior to each peak load season.

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

5.1.11 Dynamic Schedule Flows.

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

5.2 TTC/ATC/AFC Protocols – Phase 2, Market to Market. The Parties will address any appropriate revisions, subject to their respective stakeholder processes, to the requirements set forth in Section 5.1.1 through Section 5.1.11 that may arise in the implementation of Phase 2, Market to Market.

ARTICLE VI
RECIPROCAL COORDINATION OF FLOWGATES

6.1 Reciprocal Coordination of Flowgates Operating Protocols - Phase 1, Market to Non-Market.

In order to be consistent with the terminology of the Congestion Management White Paper respecting coordination of flowgates, the Parties use the following terms in this Article:

A "Coordinated Flowgate" or "CF" is a flowgate affected by the transmission of energy by a Party. A CF may be under the operational control of one of the Parties, or may be under the operational control of a third party.

A "Reciprocal Coordinated Flowgate" or "RCF" is either (1) a CF affected by the transmission of energy by both Parties, or (2) a flowgate upon which both Parties mutually agree reciprocal coordination will occur. As with a CF, a RCF may be under the operational control of one of the Parties, or may be under the operational control of a non-interested third party.

6.1.1 Reciprocal Coordinated Flowgates. In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC/ATC and calculations of firmness (firm, non-firm, network, non-firm hourly) for real-time operations applicable to the Party's CFs.

6.1.2 Coordination Process for Reciprocating Flowgates. The Parties will establish and finalize the process and timing for exchanging their respective ATC/AFC calculations and NNL calculations/allocations with respect to all RCFs. Further, the process will quantify and limit NNL, Priority 7-F, and Priority 6 – NN service on the RCFs, as well as determine priority 2-NH service. The Congestion Management White Paper provides a blueprint for the process. The procedures made under, and in compliance with this Article VI shall take into account the Congestion Management White Paper and good utility practice. For any controllable flowgate, the historically determined NNL impact on the flowgate and any allocated rights to that flowgate under this process is subject to the operating practices of the controllable device. The operating practices of the controllable device will be made available to the MIDWEST ISO and PJM before a change is made. To the extent the controllable device is able to maintain the schedule across the controllable flowgate, there are no parallel flows and a historical allocation based on parallel flows will not occur. In this instance, the use of the controllable flowgate will be limited to entities that have arranged transmission service across the interface formed by the controllable device. To the extent the controllable device cannot maintain the schedule across the controllable flowgate, there will be a historical allocation based on parallel flows.

6.1.3 Real-Time Operations Process. The Parties' capabilities and real time actions shall be governed by and in accordance with the Congestion Management White Paper.

6.2 Costs Arising From Reciprocal Coordination of Flowgates During Phase 1 and Phase 2. In the event redispatch occurs in order to coordinate congestion management under Section 6.1 or subparts thereof, during Phase 1, Market to Non-Market, including redispatch necessary to respect the other Party's flowgate, or during Phase 2, Market to Market, as set forth in Article XI, the Party responsible for the flow that required the redispatch shall bear the costs of the redispatch to the extent the costs may be recovered under the Party's OATT.

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

6.4 Maintaining Current Flowgate Models. Each Party will maintain a detailed model of the other Party's system for operations and planning purposes. PJM's model will be sufficiently detailed to properly honor all of PJM's CFs. The MIDWEST ISO's model will be sufficiently detailed to properly honor all of MIDWEST ISO's CFs. Furthermore, each Party will populate its model with credible data and will keep such models up-to-date.

6.5 Sharing Contract Path Capacity. In recognition that the Joint and Common Market is expected to eliminate distinct MIDWEST ISO contract path limits versus PJM contract path limits and in recognition that the sharing of flowgate capacity on a historical usage basis is the first step toward the elimination of distinct contract path limits, the MIDWEST ISO and PJM have agreed to the following phased approach to the elimination of such contract path limits:

(a) When PJM expands its market to include Commonwealth Edison, there will be a sharing of contract path capacity that existed on a historical basis (*i.e.*, a sharing of the combined contract path capacity where both RTOs have contract paths to the same entity). The combined contract path capacity will be made available for use by both Parties. This will not open up new paths that have not existed previously. PJM will not be able to deal directly with companies with which it does not physically interconnect and the MIDWEST ISO will not be able to deal directly with companies with which it does not physically interconnect.

(b) When the MIDWEST ISO commences operation of energy markets, the sharing of contract path capacity where the MIDWEST ISO and PJM have existing contract path capacity to the same entity will continue to exist. The MIDWEST ISO and PJM may need to resolve any coordination issues such that the combined contract capacity is not exceeded by the operation of the two markets. This phase will still not open up any new paths for the Parties.

(c) When a Joint and Common Market exists between the MIDWEST ISO and PJM as is expected, the sharing of contract path capacity between the MIDWEST ISO and PJM will occur on a complete basis. All physical connections to the combined MIDWEST ISO and PJM RTOs will be available for use by the market. Whether the physical path connections are within the MIDWEST ISO or PJM will not affect a customer's participation in the market. Only actual physical limitations will impact how the customer is able to use these connections to the market.

ARTICLE VII
COORDINATION OF OUTAGES

7.1 Coordinating Outages Operating Protocols. The Parties will jointly develop protocols for coordinating transmission and generation Outages to ensure reliability. The Parties agree to the following with respect to transmission and generation Outage coordination.

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

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

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

7.1.2 Evaluation and Coordination of Transmission and Generation Outages. The Parties will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party's Outage analysis will consider the impact of its critical Outages on the other Party's system reliability, in addition to its own. The analysis will include, as a minimum, an evaluation of contingencies, including potential real or reactive power concerns, voltage analysis and real and reactive power reserve analysis.

On a daily basis, the operations staff of each Party shall jointly discuss any Outages to identify potential impacts. These discussions should include an indication of either concurrence with the Outage or identify significant impact due to the Outage as scheduled. Neither Party has the authority to cancel the other Party's Outage (except transmission facilities interconnecting the two Parties' transmission systems). However, the Parties will work together to resolve any identified Outage conflicts. Consideration will be given to Outage submittal times and Outage criticality when addressing Outage conflicts. If Outage analysis indicates unacceptable system conditions, the Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved and make every effort to effect the requested schedule change. If this change cannot be accommodated, the Party with the Outage shall notify the impacted Party. A request to adjust a proposed Outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the Outage.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known (not to exceed thirty (30) minutes). The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work with one another to develop remedial steps as necessary.

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

ARTICLE VIII
PRINCIPLES CONCERNING JOINT OPERATIONS IN EMERGENCIES

8.1 Emergency Operating Principles.

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

Requirements:

8.1.1 In the event an emergency condition is declared in accordance with a Party's published operating protocols, the Parties will coordinate respective actions to provide immediate relief until the declaring Party eliminates the declaration of emergency. The Parties will notify each other of emergency maintenance and forced outages as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and coordinate to develop remedial steps as necessary or appropriate. If the emergency response allows for coordinating with the other Party before action must be taken, the normal RTO to RTO request for action will be followed. The Parties will conduct joint annual emergency drills and will ensure that all operating staff are trained and certified, if required, and will practice the joint emergency drills that include criteria for declaring an emergency, prioritized action plans, staffing and responsibilities, and communications.

8.1.2 In furtherance of maintaining system stability and providing prompt response to problems, the Parties agree that in situations where there is an actual IRL violation and/or the system is on the verge of imminent collapse, and when there exists an applicable emergency principles or operating guide, each Party will allow the affected Party to take immediate steps by modifying the normal RTO to RTO request procedure so that both Parties and affected operating entities can communicate and coordinate simultaneously via telephone conference call or other appropriate means. Subsequent to such anomalous operations, the requesting Party will prepare a lessons learned report and provide copies thereof to the other Party and affected operating entities. The purpose of the lesson learned report is to assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

8.1.3 Applicable emergency principles and operating guides includes:

(a) Minnesota-Eastern Wisconsin Open Phase Angle Reduction Guide

(b) Minnesota-Wisconsin Stability Interface Guide

(c) Lake Erie Emergency Re-dispatch (LEER) Guide

The Parties will work together and with the Control Areas with respect to which they serve as RTO or Reliability Coordinator to jointly develop and commit to additional emergency principles and operating guides as the need for such procedures arises.

8.1.4 TLR Level 6 may be implemented when, in the judgment of either Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that either it becomes necessary for either Party to issue a TLR Level 6 for an area that is in close electrical proximity to both of the Parties' Regions, both Parties will either issue a TLR Level 6 or redispatch without declaring a TLR, and take action(s) in kind to address the situation that prompted the TLR. These actions may include:

(a) Curtailment of equivalent amounts of firm point-to-point transactions within both Parties;

(b) Redispatching of generation within both Parties; and

(c) Load shedding within both Parties.

8.1.5 In situations where an actual IRL violation exists, or for the next contingency would exist, and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing emergency principle or operating guide, each Party will receive, and subject to the next two sentences of this Section implement, the instruction of the affected Party, communicate the instruction to the affected entity within its own boundary, or utilize telephone conference call capabilities or other appropriate means of communication to allow simultaneous coordination/communication between the Parties and the affected entity. All occurrences of this kind may be reviewed by either or both Parties after the fact, but the instruction of the affected Party shall be implemented when issued, except a Party may delay implementation in instances where a Party concludes that the requested action will result in a more serious condition on the transmission system, or the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system.

8.1.6 In a situation where an SOL violation exists within either Party's Region, or for the next contingency would exist, the Parties will work together as necessary, following good utility practices, and take action in kind as required to address the situation.

8.1.7 In its capacity as RC with respect to certain Control Areas (as applicable), each Party has the responsibility and authority to coordinate with the other Party and, as may be provided under arrangements other than this Agreement, direct emergency action on the part of generation or transmission to protect the reliability of the network. Each Party shall exercise such authority in accord with good utility practice as required to resolve emergency conditions in the other Party's Region of which it is aware and, in conjunction with its stakeholder processes, will develop detailed emergency operating procedures.

8.1.7.1 Power System Restoration. Effective procedures for restoration of the network require coordination and communication at all levels of the Parties' organizations and with their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other RTOs and operating entities in order to restore the transmission system as safely and efficiently as possible. In order to enhance the effectiveness of actual restoration operations between the Parties, the Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both Parties are positioned to better assist each other in an actual restoration.

8.1.7.2 Joint Voltage Stability Operating Protocol. Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. The Parties will coordinate their operations in accordance with good utility practice in order to maintain stable voltage profiles throughout their respective Regions. The Parties will coordinate their established daily voltage/reactive management plans. This coordination will serve to assure an adequate static and dynamic reactive supply under a credible range of system dispatch patterns across both Parties' systems and will assure the plans are complementary.

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

8.2 Compensation for Market to Non-Market Emergency Principles/Procedures. Each Party is to bear its own costs of compliance with emergency energy principles and procedures, in accordance with any applicable tariff. If a Party is required to purchase emergency energy in order to address the flow of the other Party, then the other Party shall be required to provide compensation.

ARTICLE IX
COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

9.1 Administration; Committees.

9.1.1 Joint RTO Planning Committee. The ISC shall form, as a subcommittee, a Joint RTO Planning Committee, comprised of representatives of the Parties' respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JRPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The ISC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JRPC shall coordinate the coordinated system planning under this Agreement, including the following:

(a) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JRPC shall develop common power system analysis models to perform coordinated system planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the parties, the JRPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

(b) Prepare, on a regular basis, a Coordinated System Plan as required under Section 9.3.5.

(c) Coordinate all planning activities under this Article IX, including the exchange of data under this Article.

(d) Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

(e) Meet at least a semi-annually to review and coordinate transmission planning activities.

(f) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

(g) Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.

(h) Establish working groups as necessary to provide adequate review and development of the regional plans.

(i) Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

(j) Oversee an annual meeting of the Parties' system operations, market operations, and system planning personnel (such personnel as the Parties may designate for the meeting), to review the issues impacting the coordination of these functions as they impact long range planning and the coordination of planning between the systems.

9.1.2 Inter-regional Planning Stakeholder Advisory Committee. The Parties shall form an Inter-regional Planning Stakeholder Advisory Committee. The IPSAC shall facilitate stakeholder review and input into coordinated system planning with respect to the development of the Coordinated System Plan. IPSAC members shall be the members of the MIDWEST ISO Planning Advisory Committee and the PJM Transmission Expansion Advisory Committee. Other stakeholders shall be permitted to become members of the IPSAC, including stakeholders created by change of geographic scope of a Party's Region. The IPSAC will meet no less frequently than prior to the start of each cycle of the coordinated planning process, during the development of the Coordinated System Plan, and upon completion of the Plan to review final results.

9.2 Data and Information Exchange. In support of coordinated system planning, each Party shall provide the other with the following data and information. Unless otherwise indicated, such data and information shall be provided annually.

(a) Data required for the development of load flow cases, short-circuit cases, and stability cases, including ten year load forecasts, including all critical assumptions that are used in the development of these cases.

(b) Fully detailed planning models (up to the next ten (10) years) on an annual basis and monthly updates that reflect system enhancement changes or other changes, as they occur.

(c) The regional plan document produced by the Party, any long-term or short-term reliability assessment documents produced by the Party, and any operating assessment reports produced by the Party.

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

(e) Transmission system maps for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two systems.

(f) Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party's transmission system that are relevant to the coordination of planning between the two systems.

(g) The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related applications for regulatory approval and the status thereof. This information shall be provided annually and from time to time upon changes in status.

(h) Monthly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party's system in a manner that affects the other Party's system.

(i) Quarterly, the status of all interconnection requests that have been identified.

(j) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems.

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

(l) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

9.3 Coordinated System Planning. The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 Single Party Planning. Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents the procedures, methodologies, and business rules utilized in preparing and completing the report.

9.3.2 Coordinated System Plan. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.5. The Coordinated System Plan shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party.

9.3.3 Analysis of Interconnection Requests. In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) Upon the posting to the OASIS of a request for interconnection, the Party receiving the request ("direct connect system") will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the direct connect system will notify the other Party and convey the information provided in the posting.

(b) If the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable generation interconnection procedures of the direct connect system. The potentially impacted Party will comply with this schedule.

(d) The potentially impacted Party may participate in the coordinated study either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(e) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(f) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the system impact study prepared for the interconnection customer.

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

(h) In addition, thermal and reactive impacts associated with circulation and other phenomena that result from interconnection and impact the systems of both Parties will be evaluated in the evaluation of specific requests associated with delivery service and in the development of the Coordinated System Plan.

(i) Each Party will maintain a separate interconnection queue. The JRPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The JRPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.

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

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

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

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, that Party will contact the Party receiving the request and request participation in the applicable interconnection studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable transmission service procedures of the Party receiving the request. The potentially impacted Party will comply with this schedule.

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

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

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

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

9.3.5 Development of the Coordinated System Plan.

9.3.5.1 Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party's plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered.

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or Network Upgrades; and

(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.5.2 Coordination of studies required for the development of the Coordinated System Plan will include the following steps:

(a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study. Sensitivity analyses will be performed, as required, during the off years based on a review by the JRPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues and to ensure the coordinated reliability of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented, (*e.g.*, a set number of meetings per year and/or develop a protocol for the exchange of studies, report queues, and other relevant information).

(b) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(c) The JRPC will develop a scope and procedure for the inter-regional planning assessment. The scope of the study will include evaluations of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the party's regional transmission expansion plan, and all of the committed interconnection projects and any associated Network Upgrades.

(d) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. Exchange of power flow models will be in a format that is acceptable to both Parties and will use a consistent bus numbering convention and bus naming convention to minimize work that is needed to merge detailed power flow models.

(e) The study will initially evaluate the reliability of the combined transmission systems. Any Network Upgrades required to resolve criteria violations will be agreed upon and included in an updated baseline model.

(f) The performance of the combined transmission systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Network Upgrades required to resolve operational and/or economic performance criteria violations will be included in the Coordinated System Plan.

(g) Economic criteria applicable to either Party will be developed and filed by that Party with input from its stakeholders.

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

9.4.1 Network Upgrades Associated with Interconnections. When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties' Order 2003 compliance filings as accepted by FERC.

9.4.2 Network Upgrades Associated with Transmission Service Requests. When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties' Order 2003 compliance filings as accepted by FERC.

9.4.3 Network Upgrades Under Coordinated System Plan. Cost responsibility for the Network Upgrades identified in the Coordinated System Plan to resolve thermal or reactive system constraints related to reliability criteria or operational or economic system performance will be assigned to the Parties equitably, based on the nature of the constraint being resolved. The JRPC will develop procedures for evaluating the relative contribution of the Party's systems to the constraint and the relative benefits derived by the parties by the resolution of the constraint. The JRPC will propose an allocation of costs for such Network Upgrades. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities. Stakeholder input will be taken into consideration by the JRPC in arriving at a consensus allocation of costs. Each Party will recover its allocated share of the cost of such Network Upgrades through its own OATT.

9.5 Agreement to Enforce Duties to Construct and Own. To obtain Network Upgrades under this Article IX, PJM will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the Transmission Owners Agreement, PJM Interconnection, L.L.C. First Revised Rate Schedule FERC No. 29, the West Transmission Owners Agreement, PJM Interconnection, L.L.C. Rate Schedule FERC No. 33, as either may be amended or restated from time to time, and MIDWEST ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

ARTICLE X
JOINT CHECKOUT PROCEDURES

10.1 Scheduling Checkout Protocols.

10.1.1 Scheduling Protocols. Each Party will leverage technology to perform electronic approvals of schedules and to perform electronic checkouts, in lieu of telephone calls. The Parties will follow the following scheduling protocols:

10.1.1.1 Each Party, acting as the scheduling agent for its respective Control Areas, will conduct all checkouts with first tier Control Areas. A first tier Control Area is any Control Area that is directly connected to any Party's members' Control Area or any Control Area operated by an independent transmission company.

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

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

10.1.1.4 For entities that do not use the respective Parties' electronic scheduling interfaces, the Parties will contact the non-member first-tier entities by telephone to perform checkouts.

10.1.1.5 The Parties will perform the following types of checkouts:

(a) Pre-schedule (Day-Ahead) daily between 1600 and 2000 hours:

(i) Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(b) Hourly Before the Fact (Real-Time):

(i) Hourly before the fact checkout includes the verification of import and export totals and is not limited to net scheduled interchange for Control Areas with the ability to determine such net scheduled interchange. At a future time, the Parties may checkout individual schedules.

(ii) Hourly checkout is performed starting at the half hour and ending at the ramp hour.

(c) After the fact (day end) daily starting at 0100 hours; and

(d) After the fact (monthly) daily on a month to date basis (usually via email) starting on the first business day of the following month and ending by the tenth (10^{th}) business day of that month.

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

ARTICLE XI
ADDITIONAL COORDINATION PROVISIONS

11.1 Application of Congestion Management White Paper. The Parties have agreed to certain operating protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. These protocols include the Congestion Management White Paper and applicable NERC reliability plans. As addressed in Section 3.1, the Parties expect that these systems and the operating protocols applicable to these systems will change and revisions of this Agreement will be required from time to time. Sections 11.1.1 through 11.1.5 state certain requirements applicable to PJM regarding the implementation of the Congestion Management White Paper through Phase 2.

11.1.1 Commonwealth Edison Market Integration. Effective upon PJM's inclusion of the Northern Illinois Control Area into the PJM market, PJM will implement the Congestion Management White Paper for the flowgates specified in Appendix F thereof, including all provisions for creating flowgates, adding new flowgates, and the dispute resolution process for adding flowgates. Flowgates determined only by impacts from the dynamically scheduled and NERC E-Tagged pathway between the Northern Illinois and PJM Control Areas will not be included in the PJM's coordinated flowgate list (as that term is used in the Congestion Management White Paper).

11.1.2 Integration of American Electric Power Control Area or Commencement of MIDWEST ISO Market. Upon the earlier of (a) the integration of the American Electric Power Control Area into the PJM market or (b) the commencement of the MIDWEST ISO market, and in either event, provided that Commonwealth Edison has been integrated into the PJM markets, PJM will implement the Congestion Management White Paper for the MIDWEST ISO flowgates, as defined in the Congestion Management White Paper, impacted by all Control Areas within the PJM footprint (such impact as defined under the Congestion Management White Paper), including the Northern Illinois Control Area. Such implementation will include all provisions for creating flowgates, adding new flowgates, and the dispute resolution process for adding flowgates. Flowgates determined only by impacts from the dynamically scheduled and NERC E-Tagged pathway between the Northern Illinois Control Area and PJM will be processed as described in Section 11.1.5 of this Agreement.

11.1.3 PJM Market Expands to Areas Other than Commonwealth Edison. Upon PJM expansion of its markets to areas other than the Northern Illinois Control Area, PJM will implement the Congestion Management White Paper for all MIDWEST ISO flowgates, as defined in the Congestion Management White Paper, impacted by all Control Areas in the PJM market. Flowgates determined only by impacts from the dynamically scheduled and NERC E-Tagged pathway between the Northern Illinois Control Area and the PJM Control Area, if it remains, will be processed as described in Section 11.1.5 of this Agreement.

11.1.4 PJM Market Area becomes Contiguous. In the event PJM's market includes the Northern Illinois Control Area and the Control Areas of Commonwealth Edison, American Electric Power, and Dayton Power & Light, or otherwise includes Control Areas contiguous with the PJM Control Areas existing as of the Effective Date (PJM as initially organized and Allegheny Power Company ("the pre-existing PJM Control Areas") there will no longer be a need for the dynamically scheduled and NERC E-Tagged pathway between Commonwealth Edison and the pre-existing PJM Control Areas. At such time, PJM will discontinue the dynamically scheduled and NERC E-Tagged pathway and will implement the Congestion Management White Paper for all flowgates impacted by all Control Areas in the PJM market.

11.1.5 Management of PJM – Commonwealth Edison Dynamic Schedule Pathway. During such period as the dynamically scheduled and NERC E-Tagged pathway exists between the Northern Illinois Control Area and the pre-existing PJM Control Areas to address the connection between those portions of the PJM market, PJM will comply with the following provisions in addition to the NERC Operating Policy requirements for dynamic schedules and interchange schedules. In addition to implementing applicable methodologies stated in the Congestion Management White Paper and, in accordance with the following standards, PJM shall also place limitations on its utilization of the dynamic schedule (pathway) between the Northern Illinois Control Area and PJM Control Area and manage the dynamic schedule pathway:

(a) PJM will upload to the IDC the scheduled value of the dynamic schedule when either there is a 25% net change of the schedule and/or every fifteen (15) minutes.

(b) When a reliability coordinator implements TLR 1 or higher on flowgates that the pathway flow has a 5% or greater impact upon, PJM will limit changes to the dynamic schedule that would increase flow on the impacted flowgate (decreasing flow on the impacted flowgate is permitted) as follows:

(i) To either a 200 MW change limit or 25% of the total dynamic schedule value of contributed firm transmission service whichever is smaller. These limits apply to each quarter hour increment and PJM will honor this limit throughout the TLR event. For example, if the pathway capacity was 500 MW, during a TLR 1 or higher level the dynamic schedule will be limited to a change of 125 MW every fifteen (15) minutes for a total hourly change in one direction of 500 MW.

(ii) PJM will freeze and not increase the actual value of dynamic schedule (if it impacts the constrained flowgate by 5% or more) during TLR 3B or TLR 5B for the remainder of the hour.

(iii) PJM will freeze and not increase the actual value of dynamic schedule (if it impacts the constrained flowgate by 5% or more) for next hour, during TLR 3A or TLR 5A, until the NERC TLR reallocation process can make room on the flowgate for a scheduled increase.

(iv) During a TLR Level 5, PJM will curtail the dynamic schedule per the output of the IDC.

(c) During a Disturbance Control Standard event, PJM will not increase loading of the pathway until the Control Area in which the generation loss occurs can return its ACE to the pre-disturbance value.

(d) PJM will update the NERC ISN with the value and direction of the dynamic schedule every five (5) minutes.

11.2 Additional Provisions Concerning Phase 2, Market to Market.

11.2.1 LMP Calculation Consistency. The Parties agree to ensure that LMP signals meet certain common criteria in order to achieve maximum benefits to competition from the joint and common market. In particular, the Parties agree that dispatch in both markets will be performed under a nodal pricing regime and that settlement will be based, in part, on the resulting LMPs. Given the importance of the individual LMPs, the pricing methodologies employed will result in prices that meet certain common criteria at all relevant physical interfaces between the two markets. The Parties' goal will be that the respective prices calculated by both Parties for these interfaces will be identical. Therefore, to the extent that such prices are not identical, the Parties agree to work in good faith to resolve the reasons for the differences in order to send the most consistent economic signals reasonably possible to all market participants.

The Parties further agree that the LMP formulation will be such that the optimal solution will be very close to the current system operating condition. Inputs into the Locational Marginal Pricing program will be the flexible generating units from the LMP Preprocessor, actual generation, load and system topology from the State Estimator, and binding constraints from the LMP Contingency Processor. The Parties agree to work in good faith to reach resolution on the frequency of the calculation of the prices. Additionally, the Parties agree that any changes to the pricing methodology will be coordinated across the two markets to maintain consistency.

11.2.2 Coordination Processes. As the MIDWEST ISO market is implemented and as the PJM market expands, it will become critical to coordinate the LMP-based congestion management procedures between the two markets. The Market to Market transaction scheduling processes and the LMP at the market border points must be coordinated in order to efficiently manage interregional power flows. This coordination process will ensure appropriate LMP values at the market borders and will eliminate potential inefficiencies and gaming opportunities that otherwise could be caused by uncoordinated congestion management between the adjacent markets.

11.2.3 Overview of the Market-to-Market Coordination Process. The fundamental philosophy of the Market to Market transmission congestion coordination process is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both Parties. This joint management of transmission constraints near the market borders will provide the most efficient and least costly transmission congestion management and will also provide coordinated pricing at the market boundaries.

This Market to Market coordination process builds upon the Parties' Market to Non-Market coordination process as a starting point. The Parties have agreed upon the inter-regional coordination process between a market region that uses an LMP-based congestion management regime (PJM) and a non-market region (MIDWEST ISO) that uses a TLR-based congestion management regime (*i.e*. a market to non-market interface). The set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market is identified by the Parties. These flowgates are then monitored to measure the impact of Market Flows and loop flows from adjacent regions. The procedures developed by the Parties provide a framework for calculating the resulting powerflow impacts resulting from the market-based economic dispatch in one region on the transmission facilities in an adjacent region and vice versa. In addition, the Parties have reached agreement on how the market flow impacts will be managed on an interregional basis within the existing NERC IDC to enhance the effectiveness of the NERC interregional congestion management process. Lastly, the Parties agree that flow entitlement for network and firm transmission utilization in one region has an impact on the transmission facilities in an adjacent region.

The Market to Market coordination process builds on the process described above because of the continuing requirement to coordinate with adjacent regions after the Parties' respective markets are implemented. In addition, there is a continuing need to enhance methods to define the flow entitlement for network and firm transmission utilization in one region on the transmission facilities in an adjacent region.

11.2.4 Identification of Transmission Constraints that Require Coordinated Transmission Congestion Management. A subset of transmission constraints that exist in the market of either Party, and not all such constraints, will require coordinated congestion management. This subset of transmission constraints will be identified in a manner similar to the method referred to in Section 11.2.3. The list of transmission constraints will be limited to those for which at least one generator in the adjacent market has a significant power distribution factor with respect to serving load in the adjacent region (*e.g*. 5 percent).

11.2.5 Real-time Market Coordination. When any of the transmission constraints that have been identified as requiring coordinated transmission congestion management become binding in the monitoring Party's security constrained economic dispatch, then the monitoring Party will notify the non-monitoring Party and provide the economic value of the constraint (*i.e*. the shadow price).

Using this information, the security-constrained economic dispatch of the non-monitoring Party will take the transmission constraint into account, causing that Party to redispatch generation to manage the constraint, but only if the cost of redispatch is less than the constraint shadow price as calculated by the monitoring Party.

This process will continue over the next several dispatch cycles, allowing the transmission congestion to be managed in a coordinated, cost-effective manner by the Parties. The iterative coordination process will be supported by automated data exchanges in order to ensure the process is manageable in a real-time environment.

The iterative protocol developed as of the execution of this Agreement, is stated in Sections 11.2.5.1 through 11.2.5.6, which protocol is tentative and is expected to be revised.

11.2.5.1 The Parties will exchange topology information to ensure that their respective market software is consistent.

11.2.5.2 The monitoring Party provides (i) all non-zero shadow prices and (ii) congestion relief (in MW) required to the non-monitoring Party for any of the coordinated flowgates identified by the Parties.

(a) The shadow prices are an output of the monitoring Party's real-time market software.

(b) The required relief would serve as a maximum amount of relief that can be provided by the non-monitoring Party for the interval in question – it prevents the non-monitoring Party from redispatching excessive quantities of generation.

11.2.5.3 This information is an input to the non-monitoring Party's market software, which will optimize to minimize production costs while respecting the binding constraints in the monitoring Party's area.

11.2.5.4 The initial redispatch actions determined by the non-monitoring Party's market software are then executed.

11.2.5.5 In the next interval, the monitoring Party will solve and produce new shadow prices. If the non-monitoring Party took redispatch actions to reduce its flow on the constrained flowgate, the shadow price should be reduced.

11.2.5.6 This process will continue throughout subsequent dispatch cycles, iterating towards an optimal solution where the marginal costs of redispatch to manage the binding constraint for each Party are approximately the same.

11.2.6 Results of the Approach. Under this proposed approach, the coordinated dispatch protocols will be performed any time that a transmission constraint that has been identified as requiring coordinated transmission congestion management becomes binding. This approach produces the level of coordination that is required to ensure efficient congestion management across the market seams. This approach will also provide a much higher level of interregional congestion management coordination than that which currently exists between any existing adjacent markets.

11.2.7 Real-time Market Settlements. The market settlements under the coordinated transmission congestion management will be performed based on the real-time power flow contribution on the transmission flowgate from the non-monitoring Party, as compared to its flow entitlement. If the real-time powerflow is greater than the flow entitlement, then the non-monitoring Party will pay the monitoring Party for congestion relief provided to sustain the higher level of real-time powerflow. This payment will be calculated based on the following equation:

Payment = (Real-time Powerflow MW – Flow entitlement MW) * Transmission constraint shadow price in the monitoring Party dispatch solution

If the real-time powerflow is less than the flow entitlement, then the monitoring Party will pay the non-monitoring Party for congestion relief provided at a level below the flow entitlement. This payment will be calculated based on the following equation:

Payment = (Flow entitlement MW – Real-time Powerflow MW) * Transmission constraint shadow price in the non-monitoring Party dispatch solution

These payments will be calculated on an hourly integrated basis.

Essentially, these payments for congestion management will be added into the congestion charges collected in the Party that receives the payment in order to fund the FTR credits in that Party for the hour. The Party that makes the payment will receive the revenue from excess congestion charges collected. These excess revenues will occur because the Party making the payment will be utilizing more of the flowgate than specified in its entitlement.

If the transmission congestion has occurred on the flowgate because of the derating of a facility or because of a line outage, then any resulting transmission congestion revenue inadequacy will be shared on a pro-rata basis (based on flow entitlement percentage) between the Parties.

11.2.8 Settlement of Interregional Transactions (via Proxy Buses). In order for the Market to Market coordination to function properly, the proxy bus models for the Parties must be coordinated to the same level of granularity. The proxy bus modeling approaches must be the same at the market borders.

The proxy bus models will be based on using a flow-weighted average pricing model at common tie points at the market borders. In the Day-ahead Market and in the FTR models, the flow-weighted proxy bus definitions will be used at all times. In the real-time market, if the scheduled flow and actual flow are consistent at the proxy bus location, then the flow-weighted average price will be utilized. If significant loop flows exist at any of the proxy bus border point locations then the proxy bus price will be changed to reflect actual real-time flow patterns.

11.2.9 Day-ahead Market Coordination. The redispatch protocol for interregional congestion management will normally be performed as needed in the Real-time market, however if the need for congestion relief assistance is predictable on a Day-ahead basis, the foregoing protocols will be implemented in the Day-ahead market. If the redispatch protocol is implemented in the Day-ahead market, the monitoring Party will specify the amount of scheduled flow reduction that it is requesting on a specific transmission flowgate. The non-monitoring Party will then lower the MW limit on the specified transmission flowgate. Therefore, instead of modeling the transmission flowgate constraint at the flow entitlement amount, the non-monitoring Party will model the constraint as the flow entitlement less the requested MW reduction. The adjacent Party will schedule less flow on the specified transmission flowgate in order to provide Day-ahead congestion relief for the requesting Party. The monitoring Party may then use the additional MW capability in its own Day-ahead energy market.

11.2.10 Financial Transmission Rights Allocation/Auction Coordination. The allocation of FTR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. The FTR allocation (or auction) model will essentially contain exactly the same level of detail for adjacent regions as the Day-ahead market model and the Real-time market model. Each Party will allocate (or auction) FTRs to Network and Firm Transmission customers subject to a simultaneous feasibility test that determines the amount of transmission capability that exists to support the FTRs.

The simultaneous feasibility analysis for each Party will model that Party's flow entitlement on the transmission flowgates in the adjacent region as the powerflow limit that must be respected in the FTR allocation/auction process. The transmission flowgates in each Party will be modeled in the simultaneous feasibility test at a capability value equal to the flowgate rating minus the flow entitlement that exists for flows from the adjacent market. In this way, the FTR allocation across both Parties will recognize the reciprocal transmission utilization that exists for Network and Firm transmission customers in both markets.

11.2.11 Evolution of the Market to Market Coordination Process. Nothing in this Agreement will preclude the Parties from further evolving their market coordination process in conjunction with input from their respective market monitors.

11.2.12 Coordinated Emergency Generation Redispatch. The Parties shall follow a least-cost dispatch protocol in response to system emergencies that will mitigate or stabilize the system emergency in appropriate time to prevent IRL violation, and the costs thereof shall be reflected in, and compensated through, relative LMP values. However, in the event that costs not cognizable under LMP are incurred, the Party within which the affected resources are located shall reimburse such resource for direct incremental cost, subject to inter-RTO reimbursement in the event that the costs incurred by one Party were caused by a system emergency in the other Party.

Additionally, in the absence of the need to coordinate congestion or address a system emergency, a Party shall be entitled to request that the other Party dispatch a generation unit, subject to the Parties' agreement with respect to compensation for the dispatch.

11.2.13 Joint Reliability Coordination.

11.2.13.1 **Introduction.** The following procedures shall govern the redispatch of generation to alleviate transmission congestion on selected pathways on the transmission systems operated by the Parties. The procedures shall be used solely when, in the exercise of good utility practice, a Party determines that the redispatch of generation units on the other Party's transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

11.2.13.2 Identification of Transmission Constraints.

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

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

(c) From the identified transmission constraints, the Parties shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to this Section until otherwise agreed. In reaching such agreement, the Parties shall endeavor reasonably to limit the number of transmission constraints that are subject to this Section 11.2.13 so as to minimize potential cost shifting among market participants in the Control Areas of the MIDWEST ISO and the area comprised of the PJM West Region and the PJM Control Area resulting from the redispatch of generation under this Section. Both Parties shall post the transmission operating constraints that are subject to this Section on their respective Internet sites.

11.2.13.3 Redispatch Procedures. If (i) a transmission constraint subject to this Section 11.2.13 occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the affected Party has determined that it must either use Transmission Loading Relief or other emergency procedures, then (iii) the affected Party may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraints. Upon such request, the Party so requested shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with good utility practice.

11.2.14 Locational Marginal Price Compensation.

11.2.14.1 In the event that either Party requests that the other Party redispatch generation, the requesting Party shall include the generator's offer price (in the non-requesting Party's energy market) in a reference price at the appropriate non-requesting Party generator bus in the requesting Party's State Estimator and in the calculation of real-time prices and shall include the cost of any applicable start-up and no-load fees in the cost of operating reserves for the real-time energy market; provided, however, if the energy offer price plus any applicable start-up or no-load fees exceeds $1000/megawatt-hour, then the entire cost of the redispatch will be included in the cost of operating reserves for the real-time energy market and will not be included in the real-time prices calculation.

11.2.14.2 The redispatch of a generator by either Party under Section 11.2.13 shall not be included in the determination of Locational Marginal Prices under the tariff of either Party.

11.2.15 Generator Compensation. Generators that have increased or decreased generation output above or below the level that would otherwise represent the economic dispatch level and as a result of a request made pursuant to Section 11.2.13 (the "MWh Adjustment") shall be compensated based on the following:

(a) For a positive MWh Adjustment:

Payment to Generator = MWh Adjustment * (unit offer price – marginal price at the generator bus) + any applicable start-up or no-load costs not recovered by the marginal price;

(b) For a negative MWh Adjustment:

Payment to Generator = │MWh Adjustment│ * (marginal price at the generator bus – unit offer price) + any applicable start-up or no-load costs not recovered by the marginal price.

11.2.16 Settlements.

(a) If either Party redispatches generation under Section 11.2.13, then such Party shall include in its monthly accounting and billing a payment for the costs of such redispatch as determined in accordance with this Section.

(b) If either Party redispatches generation under Section 11.2.13, then it shall include in its monthly accounting and billing a credit to each redispatched generator calculated in accordance with Section 11.2.15. Each Party shall invoice the other, and the other shall collect from its market participants and pay to the other Party on behalf of such market participants an amount equal to all such credits to generators.

(c) Unless there is a separate emergency energy transaction accompanying any generation adjustment under Section 11.2.13, there shall be no adjustment in interchange between the Parties as a result of redispatch under this Section 11.2.13. In the event that an emergency energy transaction accompanies any generation adjustment, compensation for such transaction shall be at the rates for emergency purchases and sales which have been approved by the FERC, as they may be amended from time-to-time.

ARTICLE XII
EFFECTIVE DATE AND HOLD HARMLESS

12.1 The Parties agree to file this Agreement jointly with FERC on or before December 31, 2003 and to cooperate with each other as necessary and appropriate to facilitate such filing. In that filing, the Parties shall request FERC to approve an effective date 60 days after filing ("Effective Date"). Prior to the Effective Date, upon execution by the Parties, the Parties shall commence performance, as necessary to facilitate the integration of Commonwealth Edison into the PJM system on May 1, 2004, to support the achievement of Phase 2 activities hereunder, or as otherwise provided in Section 3.2.1. Notwithstanding the prior sentence, however, Phase 1 will not commence unless and until the FERC has (a) placed into effect a solution to the "hold harmless" issues or (b) has accepted as a solution to the Hold Harmless Issues an agreement or agreements among the Michigan and Wisconsin parties (as defined in the order noted above), Commonwealth Edison, and American Electric Power.

ARTICLE XIII
JOINT RESOLUTION OF MARKET MONITOR ISSUES

13.1 **Market Monitoring Protocols.** In addition to, as otherwise already provided in this Agreement, the Parties agree to address the matters raised and recommendations contained in a filing that the Parties' respective Market Monitors made on July 28, 2003 in Docket No. EL03-35-002, in response to the FERC order issued in *Midwest Independent Transmission System Operator, Inc.,* 103 FERC ¶ 61,210**.**

ARTICLE XIV
COOPERATION AND DISPUTE RESOLUTION PROCEDURES

14.1 Administration of Agreement. The Parties have been cooperating in order that the system of Commonwealth Edison may be integrated into the PJM system upon the Effective Date, subject to the terms and conditions of Section 12.1 and to facilitate the efficient operation of the MIDWEST ISO market by December 1, 2004. Such cooperation has been occurring at task force and working committees. Such cooperation at task force or working group level will continue after the Effective Date to facilitate the performance of all Phase 1 obligations, and to enable the initiation of performance of all Phase 2 obligations.

The ISC, established under the Joint and Common Market, shall perform the following with respect to this Agreement:

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

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

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

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

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

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

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

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

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

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

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

ARTICLE XV
RELATIONSHIP OF THE PARTIES

15.1 Relationship Between this Agreement and Joint and Common Market Agreement. The Parties agree that execution of this Agreement will further enable the Parties to address many of the specific tasks that are required prior to the creation of a joint and common market between the Parties. Specifically, Articles III through XI of this Agreement detail certain assignments that may pertain to the joint and common market. To ensure efficient handling of tasks hereunder and under the Joint and Common Market Agreement, the Parties hereby agree as follows:

15.1.1 Avoiding Duplication of Efforts. The Parties agree that to the extent that the tasks specified in Articles III through XI of this Agreement are duplicative of projects being pursued under the Joint and Common Market Agreement, the Parties will utilize this Agreement to pursue those assignments to minimize duplicative efforts. The Parties therefore agree that the Joint and Common Market Agreement will be deemed to be superseded by this Agreement only to the extent necessary to accomplish the assignments in Articles III through XI.

15.1.2 Making Necessary Amendments to the Joint and Common Market Agreement. The Parties agree to amend the Joint and Common Market Agreement to carry out the purposes of Section 15.1.1 within thirty (30) days after the Effective Date of this Agreement, to the extent amendment may be required under the terms of the Joint and Common Market Agreement.

ARTICLE XVI
ACCOUNTING AND ALLOCATION OF COSTS OF JOINT OPERATIONS

16.1 Revenue Distribution. This Agreement does not modify any FERC approved agreement between a Party and the owners of the transmission facilities over which the Party exercises control with regard to revenue distribution. All distribution of revenue received under this Agreement shall be distributed by the Party receiving such revenue in accordance with the terms of such Party's agreement with the transmission owners.

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

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

ARTICLE XVII
RETAINED RIGHTS OF PARTIES

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

17.2 Agreement to Jointly Make Required Tariff Changes to Implement Agreement. The Parties agree that they shall cooperate in good faith in the filing of any Section 205 filings before FERC that may be required to implement the terms of this Agreement, including revisions to a Party's OATT as necessary to implement Sections 6.2, 6.3, 9.4.1, and 9.4.2 of this Agreement. Whenever practicable, the Parties agree that they shall make simultaneous filings with FERC concerning such tariff filings.

ARTICLE XVIII
ADDITIONAL PROVISIONS

18.1 Confidentiality.

18.1.1 Definition. The term "Confidential Information" shall mean: (a) all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (b) any information deemed confidential under some other form of confidentiality agreement or tariff provided to a Party by a generator; (c) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; (d) applicable material deemed Confidential Information pursuant to the PJM Data Confidentiality Regional Stakeholder Group, and (e) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. § 37 *et. seq*. and the Parties' Standards of Conduct on file with the FERC.

18.1.2 Protection. During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its subcontractors and its subcontractors' employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Section by its employees, its subcontractors and its subcontractors' employees and agents.

This obligation of confidentiality shall not extend to information that, at no fault of the recipient Party, is or was (1) in the public domain or generally available or known to the public; (2) disclosed to a recipient by a third party who had a legal right to do so; (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel, in which event the recipient hereby agrees to provide the issuing Party with prompt Notice of such request or requirement in order to enable the issuing Party to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event that such protective order or other remedy is not obtained, or that the issuing Party waives compliance with the provisions hereof, the recipient hereby agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

18.2 Protection of Intellectual Property.

18.2.1 Unauthorized Transfer of Third-Party Intellectual Property. In the performance of this Agreement, no Party shall transfer to the other Party any Intellectual Property the use of which by the other Party would constitute an infringement of the rights of any third party. In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of Notice shall take reasonable steps to avoid claims and mitigate losses.

18.2.2 Intellectual Property Developed Under this Agreement. In the event in the course of performing this Agreement the Parties mutually develop any new Intellectual Property that is reduced to writing, the Parties shall negotiate in good faith concerning the ownership and licensing thereof.

18.3 Indemnity.

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

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

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

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.1; or

(d) Any claim that PJM caused bodily injury to an employee of the MIDWEST ISO due to negligence, recklessness, or willful conduct of PJM.

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

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

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

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 18.2.1; or

(d) Any claim that the MIDWEST ISO caused bodily injury to an employee of PJM due to negligence, recklessness, or willful conduct of MIDWEST ISO.

18.3.3 Damages Limitation.

18.3.3.1 Except for amounts required to be paid under Article 16 and Section 11.2.16 by one Party to the other under this Agreement, and except for amounts due under Sections 18.3.1 and 18.3.2, no Party shall be liable to the other Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform this Agreement, unless such failure to perform was malicious or reckless.

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

18.4 Effective Date and Termination Provision. The term of this Agreement commences as provided in Section 12.1. The Agreement shall terminate and cease to be effective upon FERC acceptance of the mutual agreement by the Parties to terminate the Agreement or other FERC order terminating the Agreement. Nothing in this Agreement shall prejudice the right of either Party to seek termination of this Agreement under Section 206 of the Federal Power Act, or successor section or statute thereof.

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

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

18.6 No Third-Party Beneficiaries. This Agreement is intended solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on, any third party (other than the Parties' successors and permitted assigns).

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

18.8 ***Force Majeure.*** No Party shall be in breach of this Agreement to the extent and during the period such Party's performance is made impracticable by any unanticipated cause or causes beyond such Party's control and without such Party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities. Upon the occurrence of an event considered by a Party to constitute a *force majeure* event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall require no Party to settle any strike or labor dispute.

A Party claiming a *force majeure* event shall notify the other Party in writing immediately and in no event later forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

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

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

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2947
Attention: General Counsel

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

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

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

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

PJM INTERCONNECTION, L.L.C.

By: ___________________________
Name: Richard A. Wodyka
Title: Senior Vice President – RTO Coordination and Integration

Date: __________________________

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

By: ___________________________
Name: James P. Torgerson
Title: President and CEO

Date:__________________________

APPENDIX A

"Managing Congestion to Address Seams, for Congestion Management Coordination"

This document and any amendments or subsequent versions thereto are hereby incorporated and made a part of this Agreement. See http://www.nerc.com/~filez/miso-pjm.html or www.nerc.com for the current version of Managing Congestion to Address Seams, for Congestion Management Coordination.

APPENDIX B

PJM Analysis for Pathway Segments

The Pathway will be constructed of three "legs" or segments of allocated transmission service between the Northern Illinois ("NI") a/k/a Commonwealth Edison Control Area and the PJM Control Area. The pathway segments will be "NI CA – AEP – PJM CA" or "PJM CA – AEP – NI CA" only. The reservations for each of the three legs will remain on the appropriate OASIS and will not undergo a conversion process. AEP reservations allocated to the Pathway must be Firm. PJM RTO (NI CA and PJM CA) reservations may be Firm or Network Designated ("ND"). Non-firm Point to Point ("PTP") service and Network Non-Designated ("NND") (including spot in service) cannot be allocated to the Pathway. The Pathway allocation will be limited to lowest (MW) allocated service on any section (NI CA, AEP, or PJM CA). All of the Pathway segments which have been contributed to the Pathway are to be Firm (Firm PTP or Network) either through existing firm reservations, requests for redirects, or rollovers.

Customers that allocate service will not have the ability to schedule against that service for the portion (calendar month and capacity) of that service allocated to the Pathway. Customers that allocate a portion of their service shall retain that ability to schedule against the remainder of that service.

- Existing reservations will be posted to the OASIS at least one (1) month prior to Commonwealth Edison integration. Converted Point-to-Point transmission service reservations that intersect with or begin after the integration, will be posted to the PJM OASIS web page on a weekly basis. Existing and converted reservations will be posted to the OASIS at least one (1) month prior to Commonwealth Edison integration.
- Redirects will be evaluated by the appropriate transmission service provider using their existing ATC and OASIS evaluations (*i.e.*, AEP for AEP segments, etc.).

- Rollover requests will be evaluated by the appropriate transmission service provider using their existing ATC and OASIS evaluations (*i.e*., AEP for AEP segments, etc.).
- Redirect and rollover requests for the NI CA and PJM CA (Commonwealth Edison and PJM) segments will be coordinated with the MIDWEST ISO and will observe limitations on MIDWEST ISO flowgates pursuant to the MIDWEST ISO's existing process for evaluating redirects and rollovers.
- Redirect and rollover requests for the NI CA and PJM CA segments will be coordinated with third parties and observe limitations on third party systems pursuant to seam coordination agreements and/or other arrangements.

The process for reviewing any newly proposed contributed service to the Pathway (process for granting new firm service for the Pathway) is as follows:

1. Firm service must be requested on the AEP OASIS (this should exist as firm service or a new request based on firm ATC posted on the AEP OASIS). The service must be in a confirmed status on the AEP OASIS node before it can be offered for allocation. There is not a specific process for granting new service for the Pathway on either the AEP or PJM nodes. All requests for service are treated the same; they go through the existing AEP or PJM process for transmission service requests. After service has been granted on a non-discriminatory basis (placed in a "Confirmed" status on the OASIS node), the customer may offer the service to PJM. However, evaluation of new service for the NI CA and PJM CA segments will be coordinated with the MIDWEST ISO and will observe limitations on the MIDWEST ISO's system. Evaluation of new service for the NI CA and PJM CA segments will also be coordinated with third party systems pursuant to coordination agreements and/or other arrangements.

2. The shoulder segments of the Pathway (NI CA and PJM CA) will not be directly evaluated for ATC, but instead normal reservation requests will need to be made through PJM for firm service. Once this service is approved using the PJM posted ATC analysis, customers will have the option to allocate their transmission service through a new form in PJM's EES application. The customer will enter the reservation number(s) for NI CA, AEP, and/or PJM along with the time period to allocate their service to the Pathway into the EES. Transmission service in a "Confirmed" status can be allocated up to 11:00 one business day prior to the calendar month. At this time, the offers on each of the three legs will be totaled. The leg with the least amount of transmission service offered for allocation will set the Pathway limit. Transmission service in surplus of this limit will be returned to the transmission customer on a Last In First Out ("LIFO") basis.

The following are definitions for types of service that can be allocated to the Pathway:

- Yearly Firm Pathway (Firm Point-to-Point and Network Designated) is defined as service beginning on 00:00 of the first day of the calendar year and ends 00:00 on the last day of the calendar year.
- Monthly Firm Pathway is defined as a fixed month beginning on the first day of a calendar month and stops at 00:00 of the first date of the next consecutive month.

The minimum duration of service that can be allocated is one calendar month. Service that has been allocated to the Pathway cannot be retracted.

The details of the methods used to evaluate the existing transmission service or to process new requests that will become a component of the Pathway are contained in the Transmission Service Request Manual available on the PJM web at
http://www.pjm.com/documents/downloads/manuals/transmission/m02v6.pdf

Sections 2 and 3 of the manual details the procedures used for Monthly Firm and Yearly Firm respectively. The key elements are of the analysis process are provided below.

Long-Term ATC (For Monthly Requests)

Long-Term Transfer Capability is calculated by PJM using software developed to calculate AFC/ATC. The Long-Term calculations include monthly TTC, Firm ATC and Non-Firm ATC. Firm and Non-Firm ATC are calculated targeting expected system conditions.
The following notes apply to the Long-Term ATC calculations.

(a) PJM AFC/ATC software is used for the monthly (as well as hourly, daily and weekly) calculations.
(b) ATC is calculated assuming all reserved firm transmission service is used for the entire day.
(c) A modified Area Interchange control is enabled to properly model losses.
(d) To evaluate thermal and reactive constraints, a non-linear (AC) solution technique is utilized to solve the power flow.
(e) During the transfer solution, since steady-state transfer capability is being determined, all automatic devices (phase shifter and TCUL transformer taps, HVDC) are enabled. Automatic devices are disabled during contingency analysis.
(f) Seasonal Thermal Rating Sets are utilized in the analysis.
(g) The ATC program evaluates:
    a. actual thermal overloads, and
    b. post-contingency thermal overloads
(h) Reactive and stability violations are monitored using thermal limits as a proxy.

System Impact Study (For yearly requests)

A System Impact Study is a detailed analysis to determine whether requested service can be accommodated. The PJM OI performs a system impact study when the following types of services are requested:

- Long-Term Firm Point-to-Point
- Network

The System Impact Study ("SIS") is conducted to determine whether the requested service can be accommodated and if there are any constraints that need to be considered to approve a request for transmission service. The FERC comparability standard is applied in evaluating the impact of all requests. The PJM OI uses the same due diligence in completing SISs for any Eligible Customers that it uses when completing studies for any Transmission Owner that requests service.

Elements of a System Impact Study may include:

- PJM Import Capability Study ("PICS") Recalculation - The goal of PICS is to establish the amount of emergency power that can be reliably transferred to the PJM Control Area from adjacent regions in the event of a PJM generation capacity deficiency.

Deliverability Evaluation - To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of the Control Area in two ways. First, energy must be deliverable from the aggregate of resources available to the Control Area to load in portions of the Control Area experiencing a localized capacity emergency or deficiency. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of the Control Area within some bounds that separate the reliability requirements of the Control Area from the reasonable economic function of the market place.

The deliverability process ensures that the bulk electric supply system can deliver sufficient generating capacity resources so that the PJM Control Area can meet the MAAC Reliability Principles and Standards & Procedures.

The first of these tests, the load deliverability test, is the delivery of energy from the aggregate of capacity resources to an electrical area experiencing a capacity deficiency.

- The CETO/CETL Test (Capacity Emergency Transfer Objective/ Capacity Emergency Transfer Limit) evaluates the reliability of the various electrical areas within PJM and ensures that the bulk electric supply can sustain the more probable contingencies with no loss of load.

- Capacity Emergency Transfer Objective Recalculation - The CETO Test determines the necessary amount of import capability needed to keep each area within the PJM Control Area at an LOLE of no greater than one-day in ten years. Imports into the area are from either the PJM Control Area or external systems.

- Capacity Emergency Transfer Limit ("CETL") Recalculation - The goal of a PJM Subarea Capacity Emergency Transfer Limit Study is to establish the amount of emergency power that can be reliably transferred to the Subarea from the remainder of PJM and the regions adjacent to PJM in the event of a generation deficiency within the Subarea (the Subarea's CETL).

The second deliverability test, generator deliverability, tests the ability of an electrical area to export capacity resources to the remainder of the Control Area, is less common but has historically been applied in isolated situations where problems were expected to occur.

Deliverability, from the perspective of individual generator resources, ensures that, under normal transmission system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources.

Dynamics Analysis - If necessary, dynamics analysis is performed to determine if the new firm transmission service request affects the stability of the PJM Control Area power system. This analysis should only investigate contingencies affected by the requested transmission service. The power flow cases created in the previous studies are used for this evaluation.

MIDWEST ISO Coordination - Any new requests, redirects, and rollovers that have the potential to increase the Pathway capability, will be coordinated with MIDWEST ISO and:

(a) Utilize the PJM Coordinated Flowgate list;
(b) Utilize the AFC Coordination process and flowgate list (AFC flowgate list is in addition to the Coordinated Flowgate list);
(c) Will respect limits on MIDWEST ISO flowgates;
(d) Will not cause PJM's NNL allocation, per the Congestion Management White Paper to be exceeded;
(e) Will comply with the MIDWEST ISO and PJM Joint Operating Agreement to limit any network and point-to-point service to within their allocations on Coordinated Flowgates; and
(f) Adhere to the MIDWEST ISO and PJM AFC Coordination Process for Point-to-Point Service.

EES, PJM's scheduling software, will automatically check the PJM and AEP nodes to verify that all service offered for allocation is monthly or yearly Firm (Point-to-Point or Network Designated).