

PJM Interconnection, L.L.C.
Rate Schedule FERC No. 24

**AMENDED AND RESTATED
OPERATING AGREEMENT
OF
PJM INTERCONNECTION, L.L.C.**

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This Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of this 2nd day of June, 1997, amends and restates as of the Effective Date the Operating Agreement of PJM Interconnection, L.L.C. filed with the FERC on April 2, 1997, as amended.

WHEREAS, certain of the Members have previously entered into an agreement, originally dated September 26, 1956, as amended and supplemented up to and including December 31, 1996, stating “their respective rights and obligations with respect to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems” (such agreement as amended and supplemented being referred to as the “Original PJM Agreement”), and which coordinated operations and interchange came to be known as the PJM Interconnection; and

WHEREAS, pursuant to a resolution of June 16, 1993, an unincorporated association comprised of the parties to the Original PJM Agreement was formed for the purpose of implementation of the Original PJM Agreement as it then existed and as it subsequently has been amended and supplemented, such association being known as the “PJM Interconnection Association”; and

WHEREAS, because of changes in federal law and policy, the Original PJM Agreement, together with other documents and agreements, was amended, restated and submitted to FERC on December 31, 1996 to restructure fundamental aspects of the operation of the Interconnection; and

WHEREAS, so that the provisions of the Original PJM Agreement could be placed into effect consistent with a February 28, 1997 order of FERC, including those provisions related to the governance of the Interconnection, the parties to the Original PJM Agreement, along with the other interested parties, approved the conversion of the PJM Interconnection Association into the LLC pursuant to the provisions of the Delaware Limited Liability Company Act, as amended (the “Delaware LLC Act”), pursuant to a Certificate of Formation (the “Certificate of Formation”) and a Certificate of Conversion (the “Certificate of Conversion”), each filed with the Delaware Secretary of State (the “Recording Office”) on March 31, 1997; and

WHEREAS, the Members wish to amend and restate the Operating Agreement of PJM Interconnection, L.L.C. adopted in connection with the formation of the LLC and as in effect immediately prior to the Effective Date in the form set forth below; and

WHEREAS, the Members intend to form an Independent System Operator in accordance with the regulations of the Federal Energy Regulatory Commission; and

WHEREAS, the Members wish to amend and restate the Operating Agreement to provide for expansion of the operations of PJM Interconnection, L.L.C. into additional Control Areas.

Now, therefore, in consideration of the foregoing, and of the covenants and agreements hereinafter set forth, the Members hereby agree as follows:

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1. DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used in this Agreement shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Sections, Schedules, Exhibits or Appendices are to Sections, Schedules, Exhibits or Appendices of this Agreement. As used in this Agreement:

Definitions A - B

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, sections 1.9.2 or 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

Additional Day-ahead Scheduling Reserves Requirement:

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via

intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement or Operating Agreement:

“Agreement” or “Operating Agreement” shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time.

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or

(ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.44.

Base Day-ahead Scheduling Reserves Requirement:

“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Batch Load Demand Resource:

“Batch Load Demand Resource” shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” refers to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Consolidated Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement” shall mean the agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member’s self-supply of energy to serve its load, or (iii) any Member’s self-schedule of energy reported to the extent that energy serves that Member’s own load.

Credit Breach:

“Credit Breach” is the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

CTS Interface Bid:

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix.

Curtailed Service Provider:

“Curtailed Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Day-ahead Congestion Price:

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with

Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-ahead Scheduling Reserves:

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the Reliability *First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix.

Day-ahead Scheduling Reserves Requirement:

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:

“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix.

Demand Resource:

“Demand Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Section 1.5.7(b) (i) – (iii) of Schedule 6 of the Operating Agreement that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. A Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

Energy Storage Resource:

“Energy Storage Resource” shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

FERC:

“FERC” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Operating Agreement.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix.

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Definitions G - H

Generating Market Buyer:

“Generating Market Buyer” shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer’s load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

Generation Capacity Resource:

“Generation Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases, with right equivalent to ownership, a Capacity Resource or an Energy Resource within the PJM footprint. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM.

A Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the

facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hot Weather Alert:

“Hot Weather Alert” shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or *expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within* three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Independent Market Monitor, IMM, Market Monitoring Unit or MMU:

“Independent Market Monitor,” “IMM,” “Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff.

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Serving Entity:

“Load Serving Entity” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (1) serving end-users within the PJM Region, and (2) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer, or an affiliated entity, that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable

reliability criteria, including Transmission Owners' planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

"Locational Marginal Price" or "LMP" shall mean the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Long-lead Project:

"Long-lead Project" shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Definitions M - N

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Attachment M of the Tariff, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other products or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical

power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Schedule 4 hereof.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Attachment J of the PJM Tariff; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Attachment J of the PJM Tariff.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions O - P

Offer Data:

“Offer Data” shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

“Office of the Interconnection Control Center” shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

“On-Site Generators” shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Operating Day:

“Operating Day” shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

“Operating Margin” shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

“Operating Margin Customer” shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

“PJM Interchange” shall mean the following, as determined in accordance with the Schedules to the Operating Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix.

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Schedules to the Operating Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

PJM Interchange Import:

“PJM Interchange Import” shall mean the following, as determined in accordance with the Schedules to the Operating Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Market Monitor:

“PJM Market Monitor” shall mean the Market Monitoring Unit established under Attachment M to the PJM Tariff.

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Open Access Same-time Information System:

“PJM Open Access Same-time Information System” shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Attachment J to the PJM Tariff.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Section 3.3 of the Operating Agreement.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

PJM Tariff:

“PJM Tariff” or “Tariff” shall mean that certain “PJM Open Access Transmission Tariff”, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

Planning Period:

“Planning Period” shall initially mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period established under the procedures of, as applicable, the Reliability Assurance Agreement.

Planning Period Balance:

“Planning Period Balance” shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

“Planning Period Quarter” shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point-to-Point Transmission Service:

“Point-to-Point Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part II.

PRD Curve:

“PRD Curve” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

“PRD Provider” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

“PRD Reservation Price” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

“PRD Substation” shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Emergency Load Response Program:

“Pre-Emergency Load Response Program” shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1

of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

“Price Responsive Demand” shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

“Primary Reserve” shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

- (1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;
- (2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;
- (3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJMSettlements is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions Q - R

Ramping Capability:

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Prices:

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time System Energy Price:

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Regional Entity:

“Regional Entity” shall mean an organization that NERC has delegated the authority to propose and enforce reliability standards pursuant to the Federal Power Act.

Regional RTEP Project:

“Regional RTEP Project” shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Registered Entity:

“Registered Entity” shall mean the entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the PJM Governing Agreements.

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

“Regulation Zone” shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Related Parties:

“Related Parties” shall mean, solely for purposes of the governance provisions of the Operating Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of the Operating Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement:

“Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No .44, and as amended from time to time thereafter.

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in \$/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

“Reserve Zone” shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5, and the parallel provisions of Tariff, Attachment K-Appendix in compliance with Operating Agreement, Schedule 1, section 7.4.2(h), and the parallel provisions of Tariff, Attachment K-Appendix, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2, and the parallel provisions of Attachment K-Appendix; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Definitions S – T

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, sections 8.1 and 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6 section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

“Special Member” shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

“Spot Market Backup” shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

State:

“State” shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

“State Estimator” shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix.

Station Power:

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

Sub-meter:

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

“Synchronized Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

“Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for

additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

“System Energy Price” shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loading Relief Customer:

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Definitions U - Z

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix.

User Group:

“User Group” shall mean a group formed pursuant to Operating Agreement, section 8.7.

VACAR:

“VACAR” shall mean the group of five companies, consisting of Duke Energy Carolinas, LLC; Duke Energy Progress, Inc.; South Carolina Public Service Authority; South Carolina Electric and Gas Company; and Virginia Electric and Power Company.

Variable Loads:

“Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Voting Member:

“Voting Member” shall mean (i) a Member as to which no other Member is an Affiliate or Related Party, or (ii) a Member together with any other Members as to which it is an Affiliate or Related Party.

Weighted Interest:

“Weighted Interest” shall be equal to $(0.1(1/N) + 0.5(B/C) + 0.2(D/E) + 0.2(F/G))$, where:

N = the total number of Members excluding ex officio Members and State Consumer Advocates (which, for purposes of Operating Agreement, section 15.2 shall be calculated as of five o'clock p.m. Eastern Time on the date PJM declares a Member in default)

B = the Member's internal peak demand for the previous calendar year (which, for Load Serving Entities under the Reliability Assurance Agreement, shall be that used to calculate Accounted For Obligation as determined by the Office of the Interconnection pursuant to Schedule 7 of the Reliability Assurance Agreement averaged over the previous calendar year)

C = the sum of factor B for all Members

D = the Member's generating capability from Generation Capacity Resources located in the PJM Region as of January 1 of the current calendar year, determined by the Office of the Interconnection pursuant to Schedule 9 of the Reliability Assurance Agreement

E = the sum of factor D for all Members

F = the sum of the Member's circuit miles of transmission facilities multiplied by the respective operating voltage for facilities 100 kV and above as of January 1 of the current calendar year

G = the sum of factor F for all Members

Zonal Base Load:

“Zonal Base Load” shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

Zone:

“Zone” shall mean an area within the PJM Region, as set forth in Tariff, Attachment J.

2. FORMATION, NAME; PLACE OF BUSINESS

2.1 Formation of LLC; Certificate of Formation.

The Members of the LLC hereby:

- (a) acknowledge the conversion of the PJM Interconnection Association into the LLC, a limited liability company pursuant to the Act, by virtue of the filing of both the Certificate of Formation and the Certificate of Conversion with the Recording Office, effective as of March 31, 1997;
- (b) confirm and agree to their status as Members of the LLC;
- (c) enter into this Agreement for the purpose of amending and restating the rights, duties, and relationship of the Members; and
- (d) agree that if the laws of any jurisdiction in which the LLC transacts business so require, the PJM Board also shall file, with the appropriate office in that jurisdiction, any documents necessary for the LLC to qualify to transact business under such laws; and (ii) agree and obligate themselves to execute, acknowledge, and cause to be filed for record, in the place or places and manner prescribed by law, any amendments to the Certificate of Formation as may be required, either by the Act, by the laws of any jurisdiction in which the LLC transacts business, or by this Agreement, to reflect changes in the information contained therein or otherwise to comply with the requirements of law for the continuation, preservation, and operation of the LLC as a limited liability company under the Act.

2.2 Name of LLC.

The name under which the LLC shall conduct its business is “PJM Interconnection, L.L.C.”

2.3 Place of Business.

The location of the principal place of business of the LLC shall be 2750 Monroe Blvd., Audubon, Pennsylvania 19403. The LLC may also have offices at such other places both within and without the State of Delaware as the PJM Board may from time to time determine or the business of the LLC may require.

2.4 Registered Office and Registered Agent.

The street address of the initial registered office of the LLC shall be 1209 Orange Street, Wilmington, Delaware 19801, and the LLC's registered agent at such address shall be The Corporation Trust Company. The registered office and registered agent may be changed by resolution of the PJM Board.

3. PURPOSES AND POWERS OF LLC

3.1 Purposes.

The purposes of the LLC shall be:

- (a) to operate in accordance with FERC requirements as an Independent System Operator, comprised of the PJM Board, the Office of the Interconnection, and the Members Committee, with the authorities and responsibilities set forth in this Agreement;
- (b) as necessary for the operation of the PJM Region as specified above: (i) to acquire and obtain licenses, permits and approvals, (ii) to own or lease property, equipment and facilities, and (iii) to contract with third parties to obtain goods and services, provided that, the LLC may procure goods and services from a Member only after open and competitive bidding; and
- (c) to engage in any lawful business permitted by the Act or the laws of any jurisdiction in which the LLC may do business and to enter into any lawful transaction and engage in any lawful activities in furtherance of the foregoing purposes and as may be necessary, incidental or convenient to carry out the business of the LLC as contemplated by this Agreement.

3.2 Powers.

The LLC shall have the power to do any and all acts and things necessary, appropriate, advisable, or convenient for the furtherance and accomplishment of the purposes of the LLC, including, without limitation, to engage in any kind of activity and to enter into and perform obligations of any kind necessary to or in connection with, or incidental to, the accomplishment of the purposes of the LLC, so long as said activities and obligations may be lawfully engaged in or performed by a limited liability company under the Act.

3.3 Counterparty.

(a) In accordance with Section 10.1 of this Agreement, the Office of the Interconnection shall implement this Agreement and administer the PJM Tariff. Under the Tariff and this Agreement, the LLC administers the provision of transmission service and associated ancillary services to customers and operates and administers various centralized electric power and energy markets. In obtaining transmission service and in these centralized markets, customers conduct transactions with PJMSettlement as a counterparty. Market participants also may conduct bilateral transactions with other market participants and they may self-supply power and energy to the electric loads they serve. Such bilateral and self-supply arrangements are not transactions with PJMSettlement.

(b) For purposes of contracting with customers and conducting financial settlements regarding the use of the transmission capacity of the Transmission System, the LLC has established PJMSettlement. The LLC also has established PJMSettlement as the entity that is the Counterparty with respect to the agreements and transactions in the centralized markets that the LLC administers under the Tariff and the Operating Agreement (i.e., the agreements and transactions that are not bilateral arrangements between market participants or self-supply). PJMSettlement will serve as the Counterparty to Financial Transmission Rights and Auction Revenue Rights instruments held by a Market Participant. Any subsequent bilateral transfer of these instruments by the Market Participant to another Market Participant shall require the consent of PJMSettlement, but shall not implicate PJMSettlement as a contracting party with respect to such subsequent bilateral transfer.

(c) As specified in Section 11 and Schedule 4, Members agree that PJMSettlement is the Counterparty to certain transactions as specified in this Agreement and the PJM Tariff.

(d) As a party to the Consolidated Transmission Owners Agreement, the LLC has acquired the right to use the transmission capacity of the transmission system that is required to provide service under the PJM Tariff and the authorization to resell transmission service using such capacity on the transmission system. Under the Consolidated Transmission Owners Agreement, the LLC compensates the Transmission Owners for the use of their transmission capacity by distributing certain revenues to the Transmission Owners as set forth in the PJM Tariff and the Consolidated Transmission Owners Agreement. The LLC has assigned its right to use the transmission capacity of the Transmission System to PJMSettlement. Accordingly, PJMSettlement shall compensate the Transmission Owners for the use of the transmission capacity required to provide service under the PJM Tariff and this Agreement.

(e) Unless otherwise expressly stated in the PJM Tariff or this Agreement, PJMSettlement shall be the Counterparty to the customers purchasing Transmission Service and Network Integration Transmission Service, and to the other transactions with customers and other entities under the PJM Tariff and this Agreement.

(f) PJMSettlement shall not be a contracting party to other non-transmission transactions that are (i) bilateral transactions between market participants, or (ii) self-supplied or self-scheduled transactions reported to the LLC.

(g) Notwithstanding the foregoing, PJMSettlement shall not be the Counterparty with respect to agreements and transactions regarding the LLC's administration of Parts IV and VI, Schedules 1, 9 (excluding Schedule 9-PJMSettlement), 10-Michigan-Ontario Interface, 10-NERC, 10-RFC, 14, 16, 16-A, and 17 of the PJM Tariff.

(h) Confidentiality. PJMSettlement shall be bound by the same confidentiality requirements as the LLC.

(i) PJMSettlement Costs. All costs of the services provided by PJMSettlement for the benefit of Market Participants and Transmission Customers shall be included in the charges for Administrative Services set forth in Schedule 9-PJMSettlement of the PJM Tariff.

(j) Amendment of Previously Effective Arrangements.

(i) Transmission Service Agreements. Transmission Service Agreements in effect at the time this Section 3.3 becomes effective shall be deemed to be revised to include PJMSettlement as a Counterparty to the Transmission Service Agreement in the same manner and to the same extent as agreements entered after the effective date of this Section 3.3.

(ii) Reliability Pricing Model. PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions that occurred prior to the effective date of this Section 3.3 and for which delivery will occur after the effective date of this Section 3.3 in the same manner and to the same extent as transactions arising from auctions cleared after the effective date of this Section 3.3.

(iii) Auction Revenue Rights and Financial Transmission Rights. PJMSettlement shall be the Counterparty with respect to the rights and obligations arising from Auction Revenue Rights and Financial Transmission Rights acquired in an auction or assigned by PJM prior to the effective date of this Section 3.3 to the same extent as with respect to rights and obligations arising from auctions or assignments of Auction Revenue Rights and Financial Transmission Rights after the effective date of this Section 3.3.

4. EFFECTIVE DATE AND TERMINATION

4.1 Effective Date and Termination.

- (a) The existence of the LLC commenced on March 31, 1997, as provided in the Certificate of Formation and Certificate of Conversion which were filed with the Recording Office on March 31, 1997. This Agreement shall amend and restate the Operating Agreement of PJM Interconnection, LLC as of the Effective Date.
- (b) The LLC shall continue in existence until terminated in accordance with the terms of this Agreement. The withdrawal or termination of any Member is subject to the provisions of Section 18.18 of this Agreement.
- (c) Any termination of this Agreement or withdrawal of any Member from the Agreement shall be filed with the FERC pursuant to Section 205 of the Federal Power Act and shall become effective only upon the FERC's approval, acceptance without suspension, or, if suspended, the expiration of the suspension period before the FERC has issued an order on the merits of the filing.

4.2 Governing Law.

This Agreement and all questions with respect to the rights and obligations of the Members, the construction, enforcement and interpretation hereof, and the formation, administration and termination of the LLC shall be governed by the provisions of the Act and other applicable laws of the State of Delaware, and the Federal Power Act.

5. WORKING CAPITAL AND CAPITAL CONTRIBUTIONS

5.1 Funding of Working Capital and Capital Contributions.

(a) The Office of the Interconnection shall attempt to obtain financing of up to twenty-five percent (25%) of the approved annual operating budget of the LLC adopted by the PJM Board pursuant to Section 7.5.2 of this Agreement to meet the working capital needs of the LLC, which shall be limited to such working capital needs that arise from timing in cash flows from interchange accounting, tariff administration and payment of the operating costs of the Office of the Interconnection. Such financing, which shall be non-recourse to the Members of the LLC and which shall be for a stated term without penalty for prepayment, may be obtained by borrowing the amount required at market-based interest rates, negotiated on an arm's length basis, (i) from a Member or Members or (ii) from a commercial lender, supported, if necessary, by credit enhancements provided by a Member or Members; provided, however, no Member shall be obligated to provide such financing or credit enhancements. The LLC shall make such filings and seek such approvals as necessary in order for the principal, interest and fees related to any such borrowing to be repaid through charges under the PJM Tariff as appropriate under Schedule 3 of this Agreement.

(b) In the event financing of the working capital needs of the Office of the Interconnection is unavailable on commercially reasonable terms, the PJM Board may require the Members to contribute capital in the aggregate up to five million two hundred thousand dollars (\$5,200,000) for the working capital needs that could not be financed; provided that in such event each Member's obligation to contribute additional capital shall be in proportion to its Weighted Interest, multiplied by the amount so requested by the PJM Board. Each Member that contributes such capital shall be entitled to earn a return on the contribution to the extent such contribution has not been repaid, which return shall be at a fair market rate as determined by the PJM Board but in no event less than the current interest rate established pursuant to 18 C.F.R. § 35.19a(a)(2)(iii); provided further, that any Member not wanting to contribute the requested capital contribution may withdraw from the LLC upon 90 days written notice as provided in Section 18.18.2 of this Agreement.

(c) Authority to borrow capital for LLC Operations. Nothing in Section 5.1(a) and (b) shall be construed to restrict the authority of the PJM Board to authorize the LLC to borrow or raise capital in excess of twenty-five percent of the approved annual operating budget of the LLC, for working capital or otherwise, as the PJM Board deems appropriate to fund the operations of the LLC, in accordance with the general powers of the LLC under Section 3.2 to enter into obligations of any kind to accomplish the purposes of the LLC. Nor shall anything in Section 5.1(a) and (b) in any way restrict the authority of the PJM Board to authorize the LLC to grant to lenders such security interests or other rights in assets or revenues received under the PJM Tariff with respect to the costs of operating the LLC and the Office of the Interconnection and to take such other actions as it deems necessary and appropriate to obtain such financing in accordance with such general powers of the LLC under Section 3.2.

5.2 Contributions to Association.

All contributions prior to the Effective Date of the original Operating Agreement of PJM Interconnection, L.L.C. of cash or other assets to the PJM Interconnection Association by persons who are now or in the future may become Members of the LLC shall be deemed contributions by such Members to the LLC.

6. TAX STATUS AND DISTRIBUTIONS

6.1 Tax Status.

The LLC shall make all necessary filings under the applicable Treasury Regulations to have the LLC taxed as a corporation.

6.2 Return of Capital Contributions.

- (a) In the event Members are required to contribute capital to the LLC in accordance with Section 5.1 herein, the LLC shall request the Transmission Owners to recover such working capital through charges under the PJM Tariff as provided in Schedule 3 of this Agreement. In the event all or a portion of the working capital is recovered pursuant to the PJM Tariff, such amount(s) shall be returned to the Members in accordance with their actual contributions.
- (b) Except for return of capital contributions and liquidating distributions as provided in the foregoing section and Section 6.3 herein, respectively, the LLC does not intend to make any distributions of cash or other assets to its Members.

6.3 Liquidating Distribution.

Upon termination or liquidation of the LLC, the cash or other assets of the LLC shall be distributed as follows:

- (a) first, in the event the LLC has any liabilities at the time of its termination or dissolution, the LLC shall liquidate such of its assets as is necessary to satisfy such liabilities;
- (b) second, any capital contribution in cash or in kind by any Member of the PJM Interconnection Association prior to the Effective Date shall be distributed by the LLC back to such Member in the form received by the PJM Interconnection Association; and
- (c) third, any remaining assets of the LLC shall be distributed to the Members in proportion to their Weighted Interests.

7. PJM BOARD

7.1 Composition.

There shall be an LLC Board of Managers, referred to herein as the “PJM Board,” composed of nine voting members, with the President as a non-voting member. The nine voting Board Members shall be elected by the Members Committee. A Nominating Committee, consisting of one representative elected annually from each sector of the Members Committee established under Section 8.1 and three voting Board Members (provided that one such Board Member shall serve only as a non-voting member of the Nominating Committee), shall retain an independent consultant, which shall be directed to prepare a list of persons qualified and willing to serve on the PJM Board. Not later than 30 days prior to each Annual Meeting of the Members, the Nominating Committee shall distribute to the representatives on the Members Committee one nominee from among the list proposed by the independent consultant for each vacancy or expiring term on the PJM Board, along with information on the background and experience of the nominees appropriate to evaluating their fitness for service on the PJM Board; provided, however, that the Nominating Committee in its discretion may nominate, without retaining an independent consultant, a Board member whose term is expiring and who desires to serve an additional term. Elections for the PJM Board shall be held at each Annual Meeting of the Members, for the purpose of selecting the initial PJM Board in accordance with the provisions of Section 7.3(a), or selecting a person to fill the seat of a Board Member whose term is expiring. Should the Members Committee fail to elect a full PJM Board from the nominees proposed by the Nominating Committee, then the Nominating Committee shall propose a further nominee from the list prepared by the independent consultant (or a replacement consultant) for each remaining vacancy on the PJM Board for consideration by the Members at the next regular meeting of the Members Committee.

7.2 Qualifications.

A Board Member shall not be, and shall not have been at any time within two years of election to the PJM Board, a director, officer or employee of a Member or of an Affiliate or Related Party of a Member. Except as provided in the LLC's Standards of Conduct filed with the FERC, at any time while serving on the PJM Board, a Board Member shall have no direct business relationship or other affiliation with any Member or its Affiliates or Related Parties. Of the nine Board Members, four shall have expertise and experience in the areas of corporate leadership at the senior management or board of directors level, or in the professional disciplines of finance or accounting, engineering, or utility laws and regulation, one shall have expertise and experience in the operation or concerns of transmission dependent utilities, one shall have expertise and experience in the operation or planning of transmission systems, and one shall have expertise and experience in the area of commercial markets and trading and associated risk management.

7.3 Term of Office.

- (a) The persons serving as the Board of Managers of the LLC immediately prior to the Effective Date shall continue in office until the first Annual Meeting of the Members. At the first Annual Meeting of the Members, the then current members of the PJM Board who desire to continue in office shall be elected by the Members to serve until the second Annual Meeting of the Members or until their successors are elected, along with such additional persons as necessary to meet the composition requirements of Section 7.1 and the qualification requirements of Section 7.2.
- (b) A Board Member shall serve for a term of three years commencing with the Annual Meeting of the Members at which the Board Member was elected; provided, however, that two of the Board Members elected at the first Annual Meeting of the Members following the Effective Date shall be chosen by lot to serve a term of one year, three of such Board Members shall be chosen by lot to serve a term of two years and the final two such Board Members shall serve a term of three years; provided further, however, that the initial term of one of the two Board Members elected to fill one of the two new Board seats added in 2003 shall be chosen by lot to serve a term of four years and the initial term of the other Board Member elected to fill the other new Board seat added in 2003 shall serve a term of five years.
- (c) Vacancies on the PJM Board occurring between Annual Meetings of the Members shall be filled by vote of the then remaining Board Members; a Board Member so selected shall serve until the next Annual Meeting at which time a person shall be elected to serve the balance of the term of the vacant Board Seat. Removal of a Board Member shall require the approval of the Members Committee.

7.4 Quorum.

The presence in person or by telephone or other authorized electronic means of a majority of the voting Board Members shall constitute a quorum at all meetings of the PJM Board for the transaction of business except as otherwise provided by statute. If a quorum shall not be present, the Board Members then present shall have the power to adjourn the meeting from time to time, until a quorum shall be present. Provided a quorum is present at a meeting, the PJM Board shall act by majority vote of the Board Members present.

7.5 Operating and Capital Budgets; Sources and Uses of Funds.

7.5.1 Finance Committee.

(a) Not later than December 1 of each year, the entities specified below shall select the members of a Finance Committee. The Finance Committee shall be composed of two representatives elected from each sector of the Members Committee as defined in section 8.1, one representative of the Office of the Interconnection selected by the President, and two Board Members selected by the PJM Board. The Office of the Interconnection representative shall be the Chair of the Finance Committee. The Chair of the Finance Committee and the two PJM Board Members on the Finance Committee shall not vote on the recommendations of the Finance Committee to the PJM Board and Members Committee. Each Member Representative of the PJM Finance Committee shall be entitled to vote on final recommendations to the PJM Board and the PJM Members Committee. The Member Representatives shall represent the interests of their respective sectors. In accordance with sections 7.7 and 11.1 of the Operating Agreement, the Members Representatives shall avoid undue influence by any Member or group of Members on the operations of PJM and Member management of the business of PJM.

(b) The purpose of the PJM Finance Committee is to review PJM's consolidated financial statements, budgeted and actual capital costs, operating budgets and expenses, and cost management initiatives and in an advisory capacity to submit to the PJM Board its analysis of and recommendations on PJM's annual budgets and on other matters pertaining to the appropriate level of PJM's rates, proposed major new investments and allocation and disposition of funds consistent with PJM's duties and responsibilities as specified in Section 7.7 of this Agreement. The Finance Committee shall also review and comment upon any additional or amended budgets prepared by the Office of the Interconnection at the request of the PJM Board or the Members Committee. Copies of the Finance Committee's submissions to the PJM Board shall be provided to the Members Committee.

(c) The Office of the Interconnection shall prepare annual operating and capital budgets and multi-year projections of expenses and capital in accordance with processes and procedures established by the PJM Board, and shall timely submit its budgets to the Finance Committee for review. The Office of the Interconnection shall also provide the Finance Committee with such additional financial information regarding other matters pertaining to the appropriate level of PJM's rates, proposed major new investments and allocation and disposition of funds as may be reasonably requested by the Finance Committee to assist it with its review. PJM shall provide complete and transparent financial data and reporting to all Members through the PJM Finance Committee, such data and reporting to include but not necessarily be limited to: unaudited quarterly PJM financial statements; audited annual PJM financial statements; quarterly PJM FERC Form 3-Q; annual PJM FERC Form 1; and PJM budget and forecast data and Results.

7.5.2 Adoption of Budgets.

The PJM Board shall adopt, upon consideration of the advice and recommendations of the Finance Committee, operating and capital budgets for the LLC, and shall distribute to the Members for their information final annual budgets for the following fiscal year not later than 60

days prior to the beginning of each fiscal year of the LLC.

7.6 By-laws.

To the extent not inconsistent with any provision of this Agreement, the PJM Board shall adopt such by-laws establishing procedures for the implementation of this Agreement as it may deem appropriate, including but not limited to by-laws governing the scheduling, noticing and conduct of meetings of the PJM Board, selection of a Chair and Vice Chair of the PJM Board, action by the PJM Board without a meeting, and the organization and responsibilities of standing and special committees of the PJM Board. Such by-laws shall not modify or be inconsistent with any of the rights or obligations established by this Agreement.

7.7 Duties and Responsibilities of the PJM Board.

In accordance with this Agreement, the PJM Board shall supervise and oversee all matters pertaining to the PJM Region and the LLC, and carry out such other duties as are herein specified, including but not limited to the following duties and responsibilities:

- i) As its primary responsibility, ensure that the President, the other officers of the LLC, and Office of the Interconnection perform the duties and responsibilities set forth in this Agreement, including but not limited to those set forth in Sections 9.2 through 9.4 and Section 10.4 in a manner consistent with (A) the safe and reliable operation of the PJM Region, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and (C) the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Region;
- ii) Select the Officers of the LLC;
- iii) Adopt budgets for the LLC;
- iv) Approve the Regional Transmission Expansion Plan in accordance with the provisions of the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of this Agreement;
- v) On its own initiative or at the request of a User Group as specified herein, submit to the Members Committee such proposed amendments to this Agreement or any Schedule hereto, or a proposed new Schedule, as it may deem appropriate;
- vi) Petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings;
- vii) Review for consistency with the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region any change to rate design or to non-rate terms and conditions proposed by Transmission Owners for filing under section 205 of the Federal Power Act;
- viii) If and to the extent it shall deem appropriate, intervene in any proceeding at FERC initiated by the Members in accordance with Section 11.5(b), and participate in other state and federal regulatory proceedings relating to the interests of the LLC;
- ix) Review, in accordance with Section 15.1.3, determinations of the Office of the Interconnection with respect to events of default;
- x) Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to PJM Settlement and the Office of the Interconnection, including interest thereon, as to which a Member is in default;

- xi) Establish reasonable sanctions for failure of a Member to comply with its obligations under this Agreement;
- xii) Direct the Office of the Interconnection on behalf of the LLC and PJMSettlement to take appropriate legal or regulatory action against a Member (A) to recover any unpaid amounts due from the Member to the Office of the Interconnection under this Agreement and to make whole any Members subject to an assessment as a result of such unpaid amount, or (B) as may otherwise be necessary to enforce the obligations of this Agreement;
- xiii) [Reserved.]
- xiv) [Reserved.]
- xv) Solicit the views of Members on, and commission from time to time as it shall deem appropriate independent reviews of, (a) the performance of the PJM Interchange Energy Market, (b) compliance by Market Participants with the rules and requirements of the PJM Interchange Energy Market, and (c) the performance of the Office of the Interconnection under performance criteria proposed by the Members Committee and approved by the PJM Board; and
- xvi) Terminate a Member as may be appropriate under the terms of this Agreement.

8. MEMBERS COMMITTEE

8.1 Sectors.

8.1.1 Designation.

Voting on the Senior Standing Committees shall be by sectors. The Senior Standing Committee shall be composed of five sectors, one for Generation Owners, one for Other Suppliers, one for Transmission Owners, one for Electric Distributors, and one for End-Use Customers, provided that there are at least five Members in each Sector. Except as specified in Section 8.1.2, each Voting Member shall have one vote. Each Voting Member shall, within thirty (30) days after the Effective Date or, if later, thirty (30) days after becoming a Member, and thereafter not later than 10 days prior to the Annual Meeting of the Members for each annual period beginning with the Annual Meeting of the Members, submit to the President a sealed notice of the sector in which it is qualified to vote or, if qualified to participate in more than one sector, its rank order preference of the sectors in which it wishes to vote, and shall be assigned to its highest-ranked sector that has the minimum number of Members specified above. If a Member is assigned to a sector other than its highest-ranked sector in accordance with the preceding sentence, its higher sector preference or preferences shall be honored as soon as a higher-ranked sector has five or more Members. A Voting Member may designate as its voting sector any sector for which it or its Affiliate or Related Party Members is qualified. The sector designations of the Voting Members shall be announced by the Office of the Interconnection at the Annual Meeting and shall apply to all Senior Standing Committees.

8.1.2 Related Parties.

The Members in a group of Related Parties shall each be entitled to a vote, provided that all the Members in a group of Related Parties that chooses to exercise such rights shall be assigned to the Electric Distributor sector.

8.1.3 Sector Challenge.

(a) Any Member ("Challenging Member") may request that PJM review the qualification of another Member ("Challenged Member") in the Challenging Member's sector to participate in that sector. Any five Members may request that PJM review the qualification of another Member to participate in the sector in which that Member is presently assigned.

(b) A request pursuant to section 8.1.3(a) of this Agreement ("Challenge") shall be submitted in writing and shall describe the basis for the Challenge, which shall include, but not limited to, the reasons why the Challenged Member may not have any Active and Significant Business Interests in its present sector. Except for new Members, a Challenge must be submitted within 30 days after the Annual Meeting of the Members. For new Members, a Challenge must be submitted within 30 days after the meeting in which they are introduced.

(c) PJM shall review the Challenge and inform the Challenged Member of the Challenge by providing a copy of the Challenge to the Challenged Member as soon as practicable, and in no case later than 10 working days after PJM receives the Challenge.

- (d) The Challenged Member shall submit to PJM a list of the sectors in which it is qualified to vote and its rank order preference of those sectors. PJM may also request information from the Challenged Member to assist in determining the Active and Significant Business Interests of Challenged Member. The Challenged Member shall respond to any such request within 60 days from the date of the request, which shall be the date the request was issued by PJM.
- (e) Considering the sector definitions and Active and Significant Business Interests, PJM, in its sole discretion, shall determine if the Challenged Member meets the requirements to participate in its present sector. PJM shall make this determination within the later of 30 days after receiving the information provided pursuant to section 8.1.3(d) of this Agreement, or 10 days after the next scheduled meeting of the Members Committee.
- (f) If the Challenged Member does not meet the requirements for its present sector, PJM shall assign the Challenged Member to the next highest preferred sector for which it is qualified in accordance with the rank order preference established by the Challenged Member pursuant to section 8.1.3(d) of this Agreement.
- (g) PJM shall notify the Challenged Member and Challenging Member as soon as practicable after making a determination pursuant to section 8.1.3(e) of this Agreement, and shall announce the outcome of any such determination at the Members Committee meeting following PJM's decision. PJM shall disclose the identity of the Challenging Party and the Challenged Party when making the announcement.
- (h) If a sector is required pursuant to Section 8.1.3(e) it shall become effective on the date of the Members Committee meeting following PJM's decision.
- (i) Until PJM rules on a Challenge, the Challenged Member shall remain in its present sector and shall be permitted to vote in that sector.

8.2 Representatives.

8.2.1 Appointment.

Each Member may appoint one representative to serve on each of the Standing Committees, potentially a different person for each committee, with authority to act for that Member with respect to actions or decisions thereof. Each Member may appoint up to three alternate representatives to each such committee to act for that Member at meetings thereof in the absence of the representative. A Member participating in the PJM Interchange Energy Market through an agent may be represented on the Standing Committee by that agent. A Member shall appoint its representatives and alternates by giving written notice thereof to the Office of the Interconnection. Members that are Affiliates or Related Parties may each appoint a representative and alternate representatives to each of the Standing Committees, but shall vote on Senior Standing Committees as specified in Section 8.1.

8.2.2 Regulatory Authorities.

FERC and any other federal agency with regulatory authority over a Member and each State electric utility regulatory commission with regulatory jurisdiction within the PJM Region, may nominate one representative to serve as an ex officio non-voting member on each of the Standing Committees.

8.2.3 State Offices of Consumer Advocate.

(a) Each State Consumer Advocate may nominate one representative to serve as an ex officio member on each of the Standing Committees. Upon a written request by a State Consumer Advocate to the Office of the Interconnection, and upon the payment of the fee prescribed by section (b) of Schedule 3 to this Agreement, a State Consumer Advocate may designate a representative to each of the Standing Committees who, subject to subparagraph b, shall be entitled to cast one (1) non-divisible vote in the End-Use Customer Sector in Senior Standing Committees. As an ex officio member, a State Consumer Advocate shall have no liability under this Agreement, other than the annual fee required by Schedule 3. The State Consumer Advocates shall not be entitled to indemnification by the other Members under any provisions of this Agreement. Additionally, the State Consumer Advocates shall not be eligible to participate in any markets managed by PJM under the terms contained in this Agreement.

(b) Each State Consumer Advocate shall be entitled to cast only one (1) vote in the Senior Standing Committees per State or the District of Columbia. If more than one representative from a given state has been nominated to be a voting member of the Senior Standing Committees, all State Offices of Consumer Advocate from such state that have nominated representatives to vote at the Senior Standing Committees shall designate to the Office of the Interconnection one (1) representative who shall be entitled to vote on all of their behalf's, prior to being permitted to vote at any meetings of the Senior Standing Committees.

8.2.4 Initial Representatives.

Initial representatives to the Members Committee shall be appointed no later than 30 days after the Effective Date; provided, however, that each representative to the Management Committee under the Operating Agreement of PJM Interconnection, L.L.C. as in effect immediately prior to the Effective Date shall automatically become a representative to the Members Committee on the Effective Date unless replaced as specified in Section 8.2.5. An entity becoming a Member shall appoint a representative to each Standing Committee no later than 30 days after becoming a Member.

8.2.5 Change of or Substitution for a Representative.

Any Member may change its representative or alternate on the Standing Committees at any time by providing written notice to the Office of the Interconnection identifying its replacement representative or alternate. Any representative to the Standing Committees may, by written notice to the applicable Chair, designate a substitute representative from that Member to act for him or her with respect to any matter specified in such notice.

8.3 Meetings.

8.3.1 Regular and Special Meetings.

The Standing Committees shall hold regular meetings, no less frequently than once each calendar quarter at such time and at such place as shall be fixed by the Chair thereof. The Members Committee may adopt bylaws, including rules of procedure, governing its meetings and activities and the meetings and activities of the other Standing Committees, and other committees, subcommittees, task forces, working groups and other bodies under its auspices. The Members Committee shall hold an Annual Meeting of the Members each calendar year at such time and place as shall be specified by the Chair. At the Annual Meeting of the Members, Board Members as necessary shall be elected. The Standing Committees may hold special meetings for one or more designated purposes within the scope of the authority of the applicable committee when called by the Chair on the Chair's own initiative, or at the request of five or more representatives on the applicable committee. The notice of a regular or special meeting shall be distributed to the representatives as specified in Section 18.14 of this Agreement not later than seven days prior to the meeting, shall state the time and place of the meeting, and shall include an agenda sufficient to notify the representatives of the substance of matters to be considered at the meeting; provided, however, that meetings may be called on shorter notice at the discretion of the Chair as the Chair shall deem necessary to deal with an emergency or to meet a deadline for action.

8.3.2 Attendance.

Regular and special meetings may be conducted in person or by telephone, or other electronic means as authorized by the Members Committee. The attendance in person or by telephone or other electronic means of a representative or a duly designated substitute shall be required in order to vote.

8.3.3 Quorum.

The attendance as specified in Section 8.3.2 of a majority of the Voting Members from each of at least three sectors that each have at least five Members shall constitute a quorum at any meeting of the Members Committee; however, a quorum shall only require ten Voting Members from any sector that has more than 20 Voting Members. At the beginning of any meeting of the Members Committee, a determination shall be made if a quorum is present. Once the determination is made that a quorum is present at the beginning of the meeting, a quorum will be deemed to continue during the entire scheduled time of the meeting, as specified in the notice of the meeting that is published and distributed as specified in Section 8.3.1 of this Agreement. Actions taken during this scheduled time will be deemed to have been taken with a quorum present, and quorum calls are not permitted during this scheduled time. Other than actions taken during the scheduled time for meeting of the Members Committee in accordance with this rule, no action may be taken by the Members Committee at a meeting unless a quorum is present. However, if a meeting of the Members Committee extends beyond its scheduled time, any Voting Members then present shall have the right to request a quorum call. The Voting Members then present shall have the power to adjourn the meeting from time to time until a

quorum shall be present. At the discretion of the Chair, administrative or reporting items may be accomplished if a quorum is not deemed to be present. A quorum shall not be required to conduct a meeting of any Committee other than the Members Committee; however, the Chair of any committee other than the Members Committee, in his discretion, may declare adjourned any meeting which fewer than ten Members attend.

8.4 Manner of Acting.

- (a) The procedures for the conduct of meetings of the Standing Committees may be stated in bylaws adopted by the Members Committee.
- (b) In a Senior Standing Committee, each Sector shall be entitled to cast one and zero one-hundredths (1.00) Sector Votes. Each Voting Member shall be entitled to cast one (1) non-divisible vote in its sector. In the case of a Voting Member comprised of Affiliates or Related Parties, any representative, alternate or substitute of any of the Affiliated or Related Parties may cast the vote of the Voting Member. The Sector Vote of each sector shall be split into an affirmative component based on votes for the pending motion, and a negative component based on votes against the pending motion, in direct proportion to the votes cast within the sector for and against the pending motion, rounded to two decimal places.
- (c) The sum of affirmative Sector Votes necessary to pass a pending motion in a Senior Standing Committee shall be greater than (but not merely equal to) the product of .667 multiplied by the number of sectors that have at least five Members and that participated in the vote; provided, however, that the sum of the affirmative Sector Votes necessary to pass a motion to elect a Board Member or to elect the Chair or Vice Chair of the Members Committee shall be greater than (but not merely equal to) the product of .5 multiplied by the number of sectors that have at least five Members and that participated in the vote.
- (d) Voting Members not in attendance at the meeting as specified in Section 8.3.2 of this Agreement or abstaining shall not be counted as affirmative or negative votes.

8.5 Chair and Vice Chair of the Members Committee.

8.5.1 Selection and Term.

The representatives or their alternates or substitutes on the Members Committee shall elect from among the representatives a Chair and a Vice Chair. The offices of Chair and Vice Chair shall be held for a term of one year. The terms shall commence at the last regular meeting of the Members Committee each calendar year and end at the last regular meeting of the Members Committee of the following calendar year or until succession to the office occurs as specified herein. Except as specified below, at the last regular meeting of the Members Committee each calendar year, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected. If the office of Chair becomes vacant, or the Chair leaves the employment of the Member for whom the Chair is the representative, or the Chair is no longer the representative of such Member, the Vice Chair shall succeed to the office of Chair, and a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee, both such officers to serve until the last regular meeting of the Members Committee of the calendar year following such succession or election to a vacant office. If the office of Vice Chair becomes vacant, or the Vice Chair leaves the employment of the Member for whom the Vice Chair is the representative, or the Vice Chair is no longer the representative of such Member, a new Vice Chair shall be elected at the next regular or special meeting of the Members Committee.

Notwithstanding the foregoing, the Chair and Vice Chair whose terms commenced on May 1, 2003, shall hold their offices until the last regular meeting of the Members Committee in 2004, and there shall not be an election of a new Vice Chair at the last regular meeting of the Members Committee in 2003.

8.5.2 Duties.

The Chair shall call and preside at meetings of the Members Committee, and shall carry out such other responsibilities as the Members Committee shall assign. The Chair shall cause minutes of each meeting of the Members Committee to be taken and maintained, and shall cause notices of meetings of the Members Committee to be distributed. The Vice Chair shall preside at meetings of the Members Committee in the absence of the Chair, and shall otherwise act for the Chair at the Chair's request.

8.6 Senior, Standing, and Other Committees.

The Members Committee shall establish and maintain the Markets and Reliability Committee as a Senior Standing Committee. The Members Committee also shall establish and maintain the Market Implementation Committee (under the Markets and Reliability Committee), and Planning Committee and Operating Committee (both under the Markets and Reliability Committee) as Standing Committees. The Members Committee may establish or dissolve other Standing Committees from time to time. The President shall appoint the Chair and Vice Chair of each Senior Standing Committee and Standing Committee and, after consultation with the Chair of a Standing Committee, the President shall appoint the Chair and Vice Chair of any other committees.

8.6.1 Markets and Reliability Committee.

The Markets and Reliability Committee shall be established by and report to the Members Committee.

The Markets and Reliability Committee shall provide advice and recommendations concerning the reliable and secure operation of the PJM Interchange Energy Market and Ancillary Services markets, mechanisms to provide an efficient marketplace for products needed for resource adequacy and operating security, and otherwise as directed by the Members Committee. The Markets and Reliability Committee also addresses matters related to the reliable and secure operation of the PJM system and planning strategies to assure the continued ability of the Members to operate reliably and economically, consistent with reliability principles and standards.

Voting on the Markets and Reliability Committee shall be by sectors in accordance with Sections 8.1 and 8.4 of this Agreement. Neither the Markets and Reliability Committee nor the Members Committee shall have authority to control or direct the actions of the PJM Board or the Office of the Interconnection with regard to the short-term reliability of grid operations within the PJM Region. The responsibilities of the Markets and Reliability Committee shall, more specifically, include, but not be limited to, the following:

- (a) The Markets and Reliability Committee shall develop and approve a Markets and Reliability Committee Annual Plan including prioritization of planned activities and initiation of activities supporting the approved plan.
- (b) The Markets and Reliability Committee shall provide advice and recommendations concerning issues pertaining to the operation and administration of the PJM markets, including but not limited to amendments to PJM's Operating Agreement, the PJM Tariff, or market rules and procedures as necessary or appropriate to foster competition and assure the fair, reliable and efficient operation and administration of the PJM markets, as well as the reliable operation of the grid.
- (c) The Markets and Reliability Committee shall provide advice and recommendations as are necessary or appropriate to assure a high level of economy of service in the operation of the PJM

Interchange Energy Market and other markets, in accordance with established market operation principles, practices and procedures, recognizing individual participant requirements for services, contractual obligations and other pertinent factors.

(d) The Markets and Reliability Committee shall provide advice and recommendations concerning studies and analyses relating to the overall efficacy of the PJM Interchange Energy Market and in carrying out actions as may be initiated as a result thereof.

(e) The Markets and Reliability Committee shall provide advice and recommendations concerning revisions to the Operating Agreement, the Reliability Assurance Agreement, and the PJM Tariff that pertain to its areas of responsibility.

(f) The Markets and Reliability Committee shall make annual and timely recommendations concerning the generating capacity reserve requirement and related demand-side valuation factors for consideration by the Members Committee, in order to assist the Members Committee in making recommendations to the PJM Board of Managers.

(g) The Markets and Reliability Committee shall provide direction to the Market Implementation Committee, which committee shall report to the Markets and Reliability Committee. The Market Implementation Committee shall provide advice and recommendations to the Markets and Reliability Committee directed to the advancement and promotion of competitive wholesale electricity markets in the PJM Region, and perform such other functions as the Markets and Reliability Committee may direct from time to time.

(h) The Markets and Reliability Committee shall provide direction to the Operating Committee and Planning Committee, which committees shall report to the Markets and Reliability Committee. The Operating Committee shall advise the Markets and Reliability Committee and PJM on matters pertaining to the reliable and secure operation of the PJM Region and the PJM Interchange Energy Market, as appropriate, and other matters as the Markets and Reliability Committee may request. The Planning Committee shall advise the Markets and Reliability Committee and PJM on matters pertaining to system reliability, security, economy of service, and planning strategies and policies and other matters as the Markets and Reliability Committee may request. The Markets and Reliability Committee shall review technical recommendations and changes initiated by the Operating Committee and Planning Committees and provide comments as needed.

(i) The Markets and Reliability Committee shall perform such other functions, directly or through delegation to a Standing Committee, subcommittee, working group or task force reporting to the Markets and Reliability Committee, as the Members Committee may direct.

(j) The Markets and Reliability Committee shall create subcommittees, working groups or task forces when needed to assist in carrying out the duties and responsibilities of the Markets and Reliability Committee.

8.6.2 [Reserved.]

8.6.3 Other Committees and Bodies.

The Standing Committees may form, select the membership, and oversee the activities, of such other committees, subcommittees, task forces, working groups or other bodies as it shall deem appropriate, to provide advice and recommendations to the Standing Committees or Office of the Interconnection. Each such group shall terminate automatically upon completion of its assigned tasks and, if not terminated, shall terminate two years after formation unless reauthorized by the Standing Committee that directed its formation.

8.7 User Groups.

- (a) Any five or more Members sharing a common interest may form a User Group, and may invite such other Members to join the User Group as the User Group shall deem appropriate. Notification of the formation of a User Group shall be provided to all members of the Members Committee.
- (b) The Members Committee shall create a User Group composed of representatives of bona fide public interest and environmental organizations that are interested in the activities of the LLC and are willing and able to participate in such a User Group.
- (c) Meetings of User Groups shall be open to all Members and the Office of the Interconnection. Notices and agendas of meetings of a User Group shall be provided to all Members that ask to receive them.
- (d) Any recommendation or proposal for action adopted by affirmative vote of three-fourths or more of the members of a User Group shall be submitted to the Chair of the Members Committee. The Chairman shall refer the matter for consideration by the applicable Standing Committee as appropriate for consideration at that Committee's next regular meeting, occurring not earlier than 30 days after the referral, for a recommendation to the Members Committee for consideration at its next regular meeting.
- (e) If the Members Committee does not adopt a recommendation or proposal submitted by a User Group, upon vote of nine-tenths or more of the members of the User Group the recommendation or proposal may be submitted to the PJM Board for its consideration in accordance with Section 7.7(v).

8.8 Powers of the Members Committee.

The Members Committee, acting by adoption of a motion as specified in Section 8.4, shall have the power to take the actions specified in this Agreement, including:

- i) Elect the members of the PJM Board;
- ii) In accordance with the provisions of Section 18.6 of this Agreement, amend any portion of this Agreement, including the Schedules hereto, or create new Schedules, and file any such amendments or new Schedules with FERC or other regulatory body of competent jurisdiction;
- iii) Adopt bylaws that are consistent with this Agreement, as amended or restated from time to time;
- iv) Terminate this Agreement; and
- v) Provide advice and recommendations to the PJM Board and the Office of the Interconnection.

9. OFFICERS

9.1 Election and Term.

The officers of the LLC shall consist of a President, a Secretary and a Treasurer. The PJM Board may elect such other officers as it deems necessary to carry out the business of the LLC. All officers shall be elected by the PJM Board and shall hold office until the next annual meeting of the PJM Board and until their successors are elected. Any number of offices may be held by the same person, except that the offices of the President and Treasurer may not be held by the same person.

9.2 President.

The PJM Board shall appoint a President and Chief Executive Officer of the LLC (the "President"). The President shall direct and supervise the day-to-day operation of the LLC, and shall report to the PJM Board. The President shall be responsible for directing and supervising the Office of the Interconnection in the performance of the duties and responsibilities specified in Section 10.4. The President shall execute bonds, mortgages and other contracts requiring a seal, under the seal of the LLC, except where required or permitted by law to be otherwise signed and executed and except where the signing and execution thereof shall be expressly delegated by the board to some other officer or agent of the LLC. In the absence of the President or in the event of his or her inability or refusal to act, and if a vice president has been appointed by the PJM Board, the Vice President (or in the event there be more than one Vice President, the Vice Presidents in the order designated by the PJM Board in its Minutes) shall perform the duties of the President, and when so acting, shall have all the powers of and be subject to all the restrictions upon the President. The Vice President shall perform such other duties and have such other powers as the PJM Board may from time to time prescribe.

9.3 Secretary.

The Secretary shall attend all meetings of the PJM Board and record all the proceedings of the meetings of the PJM Board in a minute book to be kept for that purpose and shall perform like duties for the standing committees or special committees when required. He or she shall give, or cause to be given, notice of all special meetings of the PJM Board, and shall perform such other duties as may be prescribed by the PJM Board or President, under whose supervision he or she shall be. He or she shall have custody of the corporate seal of the LLC, and he or she, or an assistant secretary, shall have authority to affix the same to any instrument requiring it and, when so affixed, it may be attested by his or her signature or by the signature of such assistant secretary. The PJM Board may give general authority to any other officer to affix the seal of the LLC and to attest the affixing by his or her signature.

9.4 Treasurer.

The Treasurer shall have or arrange for the custody of the LLC's funds and securities and shall keep full and accurate accounts of receipts and disbursements in books belonging to the LLC and shall deposit all moneys and other valuable effects in the name and to the credit of the LLC in such depositories as may be designated by the PJM Board. The Treasurer shall disburse the funds of the LLC as may be ordered by the PJM Board, taking proper vouchers for such disbursements, and shall render to the President and PJM Board at its regular meetings, or when the PJM Board so requires, an account of his or her transactions as Treasurer and of the financial condition of the LLC. If required by the Board, the Treasurer shall give the LLC a bond (which shall be renewed periodically) in such sum and with such surety or sureties as shall be satisfactory to the PJM Board for the faithful performance of the duties of his office and of the restoration to the LLC, in case of his or her death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his or her possession or under his or her control belonging to the LLC.

9.5 Renewal of Officers; Vacancies.

Any officer elected or appointed by the PJM Board may be removed at any time by the affirmative vote of a majority of the PJM Board eligible to vote. Any vacancy occurring in any office of the LLC shall be filled by the PJM Board.

9.6 Compensation.

The salaries of all officers and agents of the LLC, and the reasonable compensation of the PJM Board, shall be fixed by the PJM Board.

10. OFFICE OF THE INTERCONNECTION

10.1 Establishment.

The Office of the Interconnection shall implement this Agreement, administer the PJM Tariff, and undertake such other responsibilities as set forth herein. All personnel of the Office of the Interconnection shall be employees of the LLC or under contract thereto. The cost of the Office of the Interconnection and expenses associated therewith, including salaries and expenses of said personnel, space and any necessary facilities or other capital expenditures, shall be recovered in accordance with Schedule 3. The Office of the Interconnection shall adopt, publish and comply with standards of conduct that satisfy the regulations of FERC.

10.2 Processes and Organization.

In order to carry out the responsibilities of the Office of the Interconnection for the safe and reliable operation of the PJM Region, the President may establish processes and organization for operating personnel and facilities as the President shall deem appropriate, and shall request such Members as the President shall deem appropriate to participate in such processes and organization. All such processes and organization shall be carried out in accordance with all applicable code of conduct or other functional separation requirements of FERC.

10.2.1 Financial Interests:

No Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, shall own, control or hold with power to vote Prohibited Securities subject to the following:

1. Each Office of the Interconnection Board Member, officer, or employee or spouse or dependent children thereof, shall divest of those Prohibited Securities within six (6) months of: (i) the time of his affiliation or employment with the Office of the Interconnection, (ii) the time a new Member is added to this Agreement, a new Eligible Customer begins taking service under the Tariff or a Nonincumbent Developer is pre-qualified as eligible to be a Designated Entity pursuant to schedule 6 of this Agreement, where the Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof owns such Prohibited Securities; or (iii) the time of receipt of such Prohibited Securities (*e.g.* marriage, bequest, gift, etc.).
2. Nothing in this Section 10.2.1 shall be interpreted to preclude a Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, from indirectly owning publicly traded Prohibited Securities through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted towards, or principally comprised of, entities in the electric industry or the electric utility industry, or any segments thereof) under which the Board Member, officer or employee of the Office of the Interconnection, or spouse or dependent children thereof, does not control the purchase or sale of such Prohibited Securities. Any such ownership, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.
3. Ownership of Prohibited Securities as part of a pension plan or fund of a Member, Eligible Customer or Nonincumbent Developer shall be permitted. Any such ownership, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.
4. Ownership of Prohibited Securities by a spouse of a Board Member, officer or employee of the Office of the Interconnection who is employed by a Member, Eligible Customer or Nonincumbent Developer and is required to purchase and maintain ownership of Securities of such Member, Eligible Customer or Nonincumbent Developer as a part of his or her employment shall be permitted. Any such ownership by a spouse, including the nature and conditions of the interest, must be disclosed to the Office of the Interconnection's director, regulatory oversight and compliance who will report it to the PJM Board.
5. A Board Member shall disclose to the PJM Board if the Board Member is aware that he or she, or an immediate family member, has a financial interest in a Member, Eligible Customer or Nonincumbent Developer, or their Affiliates that is subject to a matter before the PJM Board. The chair of the PJM Board Governance Committee and the Office of the

Interconnection legal counsel shall consult with the Board Member to determine whether the PJM Board Member should be recused from the PJM Board deliberations and decision making regarding the matter before the PJM Board.

10.3 Confidential Information.

The Office of the Interconnection shall comply with the requirements of Section 18.17 with respect to any proprietary or confidential information received from or about any Member.

10.4 Duties and Responsibilities.

The Office of the Interconnection, under the direction of the President as supervised and overseen by the PJM Board, shall carry out the following duties and responsibilities, in accordance with the provisions of this Agreement:

- i) Administer and implement this Agreement;
- ii) Perform such functions in furtherance of this Agreement as the PJM Board, acting within the scope of its duties and responsibilities under this Agreement, may direct;
- iii) Prepare, maintain, update and disseminate the PJM Manuals;
- iv) Comply with NERC, and Applicable Regional Entity operation and planning standards, principles and guidelines;
- v) Maintain an appropriately trained workforce, and such equipment and facilities, including computer hardware and software and backup power supplies, as necessary or appropriate to implement or administer this Agreement;
- vi) Direct the operation and coordinate the maintenance of the facilities of the PJM Region used for both load and reactive supply, so as to maintain reliability of service and obtain the benefits of pooling and interchange consistent with this Agreement, and the Reliability Assurance Agreement;
- vii) Direct the operation and coordinate the maintenance of the bulk power supply facilities of the PJM Region with such facilities and systems of others not party to this Agreement in accordance with agreements between the LLC and such other systems to secure reliability and continuity of service and other advantages of pooling on a regional basis;
- viii) Perform interchange accounting and maintain records pertaining to the operation of the PJM Interchange Energy Market and the PJM Region;
- ix) Notify the Members of the receipt of any application to become a Member, and of the action of the Office of the Interconnection on such application, including but not limited to the completion of integration of a new Member's system into the PJM Region, as specified in Section 11.6(f);
- x) Calculate the Weighted Interest and Default Allocation Assessment of each Member;
- xi) Maintain accurate records of the sectors in which each Voting Member is entitled to vote, and calculate the results of any vote taken in the Members Committee;
- xii) Furnish appropriate information and reports as are required to keep the Members regularly informed of the outlook for, the functioning of, and results achieved by the PJM Region;

- xiii) File with FERC on behalf of the Members any amendments to this Agreement or the Schedules hereto, any new Schedules hereto, and make any other regulatory filings on behalf of the Members or the LLC necessary to implement this Agreement;
- xiv) At the direction of the PJM Board, submit comments to regulatory authorities on matters pertinent to the PJM Region;
- xv) Consult with the standing or other committees established pursuant to Section 8.6(a) on matters within the responsibility of the committee;
- xvi) Perform operating studies of the bulk power supply facilities of the PJM Region and make such recommendations and initiate such actions as may be necessary to maintain reliable operation of the PJM Region;
- xvii) Accept, on behalf of the Members, notices served under this Agreement;
- xviii) Perform those functions and undertake those responsibilities transferred to it under the Consolidated Transmission Owners Agreement including (A) directing the operation of the transmission facilities of the parties to the Consolidated Transmission Owners Agreement (B) administering the PJM Tariff, and (C) administering the Regional Transmission Expansion Planning Protocol set forth as Schedule 6 to this Agreement;
- xix) Perform those functions and undertake those responsibilities transferred to it under the Reliability Assurance Agreement, as specified in Schedule 8 of this Agreement;
- xx) Monitor the operation of the PJM Region, ensure that appropriate Emergency plans are in place and appropriate Emergency drills are conducted, declare the existence of an Emergency, and direct the operations of the Members as necessary to manage, alleviate or end an Emergency;
- xxi) Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices;
- xxii) Initiate such legal or regulatory proceedings as directed by the PJM Board to enforce the obligations of this Agreement; and
- xxiii) Select an individual to serve as the Alternate Dispute Resolution Coordinator as specified in the PJM Dispute Resolution Procedures.

11. MEMBERS

11.1 Management Rights.

The Members or any of them shall not take part in the management of the business of, and shall not transact any business for, the LLC in their capacity as Members, nor shall they have power to sign for or to bind the LLC.

11.2 Other Activities.

Except as otherwise expressly provided herein, any Member may engage in or possess any interest in another business or venture of any nature and description, independently or with others, even if such activities compete directly with the business of the LLC, and neither the LLC nor any Member hereof shall have any rights in or to any such independent ventures or the income or profits derived therefrom.

11.3 Member Responsibilities.

11.3.1 General.

To facilitate and provide for the work of the Office of the Interconnection and of the several committees appointed by the Members Committee, each Member shall, to the extent applicable;

(a) Maintain complete and accurate records, if any, required to meet the purposes of this section and, subject to the provisions of this Agreement for the protection of the confidentiality of proprietary or commercially sensitive information, provide, as reasonably requested, data (excluding transactional data), documents, or records, to the Office of the Interconnection required for the following purposes: (i) maintenance of correct and updated Member and Affiliate Information, including appropriate personnel contacts, PJM committee representatives, organizational structure and other information as reasonably requested by the Office of the Interconnection to ensure the accuracy and completeness of Member records, (ii) maintenance of correct and updated Member and Affiliate Information on unit ownership, unit offer determination, unit offer submissions and unit operation, (iii) coordination of operations, (iv) accounting for all interchange transactions, (v) preparation of required reports, (vi) coordination of planning, including those data required for capacity accounting under the Reliability Assurance Agreement; (vii) preparation of maintenance schedules, (viii) analysis of system disturbances, and (ix) such other purposes, including those set forth in Schedule 2, as will contribute to the reliable and economic operation of the PJM Region and the administration by the Office of the Interconnection of the Agreement, the PJM Tariff and PJM Manuals – For the purposes of this subsection, Member and Affiliate Information means information regarding Members and either: (1) their direct and/or indirect subsidiaries subject to the jurisdiction of the FERC, or (2) their Related Parties;

(b) Provide such recording, telemetering, revenue quality metering, communication and control facilities as are required for the coordination of its operations with the Office of the Interconnection and those of the other Members and to enable the Office of the Interconnection to operate the PJM Region and otherwise implement and administer this Agreement, including equipment required in normal and Emergency operations and for the recording and analysis of system disturbances;

(c) Provide adequate and properly trained personnel to (i) permit participation in the coordinated operation of the PJM Region (ii) meet its obligation on a timely basis for supply of records and data, (iii) serve on committees and participate in their investigations, and (iv) share in the representation of the Interconnection in inter-regional and national reliability activities. Minimum training for Members that operate Market Operations Centers and local control centers shall include compliance with the applicable training standards and requirements in PJM Manual 40, Control Center Requirements, including the PJM System Operator Training Requirements in Attachment C;

(d) Share in the costs of committee activities and investigations (including costs of consultants, computer time and other appropriate items), communication facilities used by all the Members (in addition to those provided in the Office of the Interconnection), and such other

expenses as are approved for payment by the PJM Board, such costs to be recovered as provided in Schedule 3;

(e) Comply with the requirements of the PJM Manuals and all directives of the Office of the Interconnection to take any action for the purpose of managing, alleviating or ending an Emergency, and authorize the Office of the Interconnection to direct the transfer or interruption of the delivery of energy on their behalf to meet an Emergency and to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, and be subject to the emergency procedure charges specified in Schedule 9 of this Agreement for any failure to follow the Emergency instructions of the Office of the Interconnection. In addressing any Emergency, the Office of the Interconnection shall comply with the terms of any reserve sharing agreements in effect for any part of the PJM Region.

11.3.2 Facilities Planning and Operation.

Consistent with and subject to the requirements of this Agreement, the PJM Tariff, the governing agreements of each Applicable Regional Entity, the Reliability Assurance Agreement, the Consolidated Transmission Owners Agreement, and the PJM Manuals, each Member shall cooperate with the other Members in the coordinated planning and operation of the facilities of its System within the PJM Region so as to obtain the greatest practicable degree of reliability, compatible economy and other advantages from such coordinated planning and operation. In furtherance of such cooperation each Member shall, as applicable:

(a) Consult with the other Members and the Office of the Interconnection, and coordinate the installation of its electric generation and Transmission Facilities with those of such other Members so as to maintain reliable service in the PJM Region;

(b) Coordinate with the other Members, the Office of the Interconnection and with others in the planning and operation of the regional facilities to secure a high level of reliability and continuity of service and other advantages;

(c) Cooperate with the other Members and the Office of the Interconnection in the implementation of all policies and procedures established pursuant to this Agreement for dealing with Emergencies, including but not limited to policies and procedures for maintaining or arranging for a portion of a Member's Generation Capacity Resources, at least equal to the applicable levels established from time to time by the Office of the Interconnection, to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

(d) Cooperate with the members of each Applicable Regional Entity to augment the reliability of the bulk power supply facilities of the region and comply with Applicable Regional Entities and NERC operating and planning standards, principles and guidelines and the PJM Manuals implementing such standards, principles and guidelines;

(e) Obtain or arrange for transmission service as appropriate to carry out this Agreement;

- (f) Cooperate with the Office of the Interconnection's coordination of the operating and maintenance schedules of the Member's generating and Transmission Facilities with the facilities of other Members to maintain reliable service to its own customers and those of the other Members and to obtain economic efficiencies consistent therewith;
- (g) Cooperate with the other Members and the Office of the Interconnection in the analysis, formulation and implementation of plans to prevent or eliminate conditions that impair the reliability of the PJM Region; and
- (h) Adopt and apply standards adopted pursuant to this Agreement and conforming to NERC, and Applicable Regional Entity standards, principles and guidelines and the PJM Manuals, for system design, equipment ratings, operating practices and maintenance practices.

11.3.3 Electric Distributors.

In addition to any of the foregoing responsibilities that may be applicable, each Member that is an Electric Distributor, whether or not that Member votes in the Members Committee in the Electric Distributor sector or meets the eligibility requirements for any other sector of the Members Committee, shall:

- (a) Accept, comply with or be compatible with all standards applicable within the PJM Region with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals, or be subject to an interconnected Member's requirements relating to the foregoing, so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region;
- (b) Assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting automatically or manually with the Office of the Interconnection as it directs the operation of the PJM Region;
- (c) Maintain or arrange for a portion of its connected load to be subject to control by automatic underfrequency, under-voltage, or other load-shedding devices at least equal to the levels established pursuant to the Reliability Assurance Agreement, or be subject to another Member's control for these purposes;
- (d) Provide or arrange for sufficient reactive capability and voltage control facilities to conform to Good Utility Practice and (i) to meet the reactive requirements of its system and customers and (ii) to maintain adequate voltage levels and the stability required by the bulk power supply facilities of the PJM Region;
- (e) Shed connected load, share Generation Capacity Resources and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in Emergencies;

- (f) Maintain or arrange for a portion of its Generation Capacity Resources at least equal to the level established pursuant to the Reliability Assurance Agreement to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;
- (g) Provide or arrange through another Member for the services of a 24-hour local control center to coordinate with the Office of the Interconnection, each such control center to be furnished with appropriate telemetry equipment as specified in the PJM Manuals, and to be staffed by system operators trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner. In addition to meeting any training standards and requirements specified in this Agreement, local control center staff shall be required to meet applicable training standards and requirements in PJM Manual 40, Control Center Requirements, including the PJM System Operator Training Requirements in Attachment C;
- (h) Provide to the Office of the Interconnection all System, accounting, customer tracking, load forecasting (including all load to be served from its System) and other data necessary or appropriate to implement or administer this Agreement, and the Reliability Assurance Agreement; and
- (i) Comply with the underfrequency relay obligations and charges specified in Schedule 7 of this Agreement.

11.3.4 Reports to the Office of the Interconnection.

Each Member shall report as promptly as possible to the Office of the Interconnection any changes in its operating practices and procedures relating to the reliability of the bulk power supply facilities of the PJM Region. The Office of the Interconnection shall review such reports, and if any change in an operating practice or procedure of the Member is not in accord with the established operating principles, practices and procedures for the PJM Region and such change adversely affects such region and regional reliability, it shall so inform such Member, and the other Members through their representative on the Operating Committee, and shall direct that such change be modified to conform to the established operating principles, practices and procedures.

11.4 Regional Transmission Expansion Planning Protocol.

The Members shall participate in regional transmission expansion planning in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 to this Agreement.

11.5 Member Right to Petition.

(a) Nothing herein shall deprive any Member of the right to petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the petitioning Member believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any other Member (a) to oppose said proposal, or (b) to withdraw from the LLC pursuant to Section 4.1.

(b) Nothing herein shall be construed as affecting in any way the right of the Members, acting pursuant to a vote of the Members Committee as specified in Section 8.4, unilaterally to make an application to FERC for a change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, under section 205 of the Federal Power Act and pursuant to the rules and regulations promulgated by FERC thereunder, subject to the right of any Member that voted against such change in any rate, charge, classification, tariff or service, or any rule or regulation related thereto, to intervene in opposition to any such application.

11.6 Membership Requirements.

- (a) To qualify as a Member, an entity shall:
 - i) Be a Transmission Owner a Generation Owner, an Other Supplier, an Electric Distributor, or an End-Use Customer; and
 - ii) Accept the obligations set forth in this Agreement.
- (b) Certain Members that are Load Serving Entities are parties to the Reliability Assurance Agreement. Upon becoming a Member, any entity that is a Load Serving Entity in the PJM Region and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement
- (c) An entity that wishes to become a party to this Agreement shall apply, in writing, to the President setting forth its request, its qualifications for membership, its agreement to supply data as specified in this Agreement, its agreement to pay all costs and expenses in accordance with Schedule 3, and providing all information specified pursuant to the Schedules to this Agreement for entities that wish to become Market Participants. Any such application that meets all applicable requirements shall be approved by the President within sixty (60) days.
- (d) Nothing in this Section 11 is intended to remove, in any respect, the choice of participation by other utility companies or organizations in the operation of the PJM Region through inclusion in the System of a Member.
- (e) An entity whose application is accepted by the President pursuant to Section 11.6(c) shall execute a supplement to this Agreement in substantially the form prescribed in Schedule 4, which supplement shall be countersigned by the President. The entity shall become a Member effective on the date the supplement is countersigned by the President.
- (f) Entities whose applications contemplate expansion or rearrangement of the PJM Region may become Members promptly as described in Sections 11.6(c) and 11.6(e) above, but the integration of the applicant's system into all of the operation and accounting provisions of this Agreement and the Reliability Assurance Agreement, shall occur only after completion of all required installations and modifications of metering, communications, computer programming, and other necessary and appropriate facilities and procedures, as determined by the Office of the Interconnection. The Office of the Interconnection shall notify the other Members when such integration has occurred.
- (g) Entities that become Members will be listed in Schedule 12 of this Agreement.
- (h) In accordance with this Agreement, Members agree that PJMSettlement shall be the Counterparty with respect to certain transactions under the PJM Tariff and this Agreement.

11.7 Associate Membership Requirements.

- (a) If any of the following conditions apply, an entity may qualify as an Associate Member:
 - (i) The entity is not a member of the End-Use Customer sector and has not been a Market Participant over the past six months, and has no verifiable plans to become a Market Participant over the next six months;
 - (ii) The entity does not meet the requirements of Section 11.6 of this Agreement;
- (b) The following rights and obligations shall apply to Associate Members:
 - (i) Associate Members shall pay the one half of the annual membership fee, and the application fee is waived;
 - (ii) Associate Members may participate in all stakeholder process activities;
 - (iii) Associate Members shall not vote in any stakeholder activities, working groups or committees;
 - (iv) Associate Members shall not participate in any of PJM's markets;
 - (v) Associate Members may become Members if they meet the requirements of Section 1.24 of this Agreement;
 - (vi) Associate Members may participate in training offered by PJM at no cost;
 - (vii) Associate Members shall not be subject to default assessments pursuant to this Agreement.

12. TRANSFERS OF MEMBERSHIP INTEREST

The rights and obligations created by this Agreement shall inure to and bind the successors and assigns of such Member; provided, however, that the rights and obligations of any Member hereunder shall not be assigned without the approval of the Members Committee except as to a successor in operation of a Member's electric operating properties by reason of a merger, consolidation, reorganization, sale, spin-off, or foreclosure, as a result of which substantially all such electric operating properties are acquired by such a successor, and such successor becomes a Member.

13. INTERCHANGE

13.1 Interchange Arrangements with Non-Members.

Any Member may enter into interchange arrangements with others that are not Members with respect to the delivery or receipt of capacity and energy to fulfill its obligations hereunder or for any other purpose, subject to the standards and requirements established in or pursuant to this Agreement.

13.2 Energy Market.

The Office of the Interconnection shall administer an efficient energy market within the PJM Region, to be known as the PJM Interchange Energy Market, in which Members may buy and sell energy. The Office of the Interconnection will schedule in advance and dispatch generation on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by sellers within and into the PJM Region, continuing until sufficient generation is dispatched to serve the energy purchase requirements of such region and buyers out of such region, as well as the requirements of the PJM Region for ancillary services provided by such generation. Scheduling and dispatch shall be conducted in accordance with applicable schedules to the PJM Tariff and the Schedules to this Agreement.

14. METERING

14.1 Installation, Maintenance and Reading of Meters.

The quantities of electric energy involved in determination of the amounts of the billing rendered hereunder shall be ascertained by means of meters installed, maintained and read either at the expense of the party on whose premises the meters are located or as otherwise provided for by agreement between the parties concerned.

14.2 Metering Procedures.

Procedures with respect to maintenance, testing, calibrating, correction and registration records, and precision tolerance of all metering equipment shall be in accordance with Good Utility Practice. The expense of testing any meter shall be borne by the party owning such meter, except that when a meter tested upon request of another party is found to register within the established tolerance the party making the request shall bear the expense of such test.

14.3 Integrated Megawatt-Hours.

All metering of energy required herein shall be the integration of megawatt hours in the clock hour, and the quantities thus obtained shall constitute the megawatt load for such clock hour; provided, however, that adjustment shall be made for other contractual obligations of any Member as may be required to determine the quantity to be accounted for hereunder, and for transmission losses.

14.4 Meter Locations.

The meter locations to be used by the Members in determining their energy transactions on the PJM Region shall be as reasonably determined from time to time by the Member or the Office of the Interconnection.

14.5 Metering of Behind The Meter Generation.

Generating units, designated as Behind The Meter Generation, individually rated at ten megawatts or greater or that otherwise have been identified by the Office of the Interconnection as requiring metering for operational security reasons must have both revenue quality metering and telemetry equipment for operational security purposes. Multiple generating units, designated as Behind The Meter Generation, that are individually rated less than ten megawatts but together total more than ten megawatts and are identified by the Office of the Interconnection as requiring revenue quality metering and telemetry equipment may meet these metering requirements by being metered as a single unit.

14A. TRANSMISSION LOSSES

14A.1 Description of Transmission Losses.

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines and other transmission facilities.

14A.2 Inclusion of Transmission Losses.

Whenever in this Agreement, transmission losses are included in the determination of a charge, credit, load (including deviations), or demand reduction, it is explicitly so stated and such included losses shall be those losses incurred on all Transmission Facilities (to facilitate such calculation, Transmission Owners shall ensure that all such facilities are included in the PJM network model) and those losses incurred on generator step-up transformers that a Market Seller has not elected to remove from the loss calculation. Absent such explicit statement, such losses are not included in the determination.

14A.3 Other Losses.

Losses incurred on facilities other than those addressed in the preceding section may be included in the determination of charges, credits, load (including real-time deviations), or demand reductions as determined by electric distribution companies, unless this Agreement explicitly excludes such losses.

14B BILLING AND PAYMENT

14B.1 Billing Procedure:

PJMSettlement shall issue bills and billing statements pursuant to the provisions in this section 14B on behalf of itself and as agent for the Office of the Interconnection, as applicable. Payment of bills pursuant to this section 14B shall be made for the benefit of PJMSettlement and the Office of the Interconnection, as applicable.

(a) Monthly Bills. By the fifth business day of each month, PJM Settlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall issue a bill to Members and other entities for monthly activity and detailing the charges and credits for all services furnished under this Agreement, the PJM Tariff and any service or rate schedule during the preceding month (“billing month”), excluding amounts billed pursuant to weekly bills for activity during the preceding month.

(b) Weekly Bills. By 5:00 p.m. Eastern Prevailing Time each Tuesday (or Wednesday in the event that a Tuesday is a holiday), PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, will issue a weekly bill to Members and other entities for all activity for certain services furnished under this Agreement, the PJM Tariff and any service or rate schedule for the days of the billing month during the week ending the prior Wednesday. The services for which such weekly bills shall be issued are set forth in PJM Manual 29.

(c) Billing Statement. PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall provide Members and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Member’s or other entity’s activity during the billing month and amounts due, net of activity previously billed.

14B.2 Payments:

(a) **Monthly Bills.** Net amounts due to PJMSettlement, in its own name or as agent for the LLC, as applicable, pursuant to a monthly bill shall be due and payable by the Member or other entity no later than noon Eastern Prevailing Time on the due date of the first weekly bill issued for activity in the month that the monthly bill is issued. It is possible, due to the timing of holidays, that the billing and payment cycle for monthly bills stated here would call for payment of a monthly bill on a Friday that occurs less than three business days after the issuance of the bill by PJM. Where this occurs, the payment period of the monthly bill will be extended such that payment will be due when payment for the second weekly bill is due.

(b) **Weekly Bills.** Net amounts due to PJMSettlement, in its own name or as agent for the LLC, as applicable, pursuant to a weekly bill shall be due and payable by the Member or other entity no later than noon Eastern Prevailing Time on the third business day following the issuance of the weekly bill. Weekly bills issued after 5:00 p.m. Eastern Prevailing Time shall be considered to be issued the following business day.

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 14B.1 when due, the LLC may allow a municipal electric system to make arrangements with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

- (a) the LLC determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;
- (b) the municipal electric system reimburses PJM for the actual cost of such working capital;
- (c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;
- (d) PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 14B.1 above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 14B.2(a);
- (e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

(f) the municipal electric system provides the LLC with at least one week of notice (though PJM may waive this provision), and;

(g) the accumulated duration of such postponed payments shall not exceed three months in a rolling twelve-month period.

PJM may terminate this payment option at any time it determines its excess working capital is no longer sufficient to allow further or continued extension financing. In such cases, PJM shall attempt to give five business days, but not less than three business days notice to the affected municipal electric system, and may call for immediate reimbursement of any outstanding amounts owed by the municipal electric system.

(c) Form of Payments. All payments tendered in satisfaction of a Member's or other entity's obligations to PJMSettlement or the LLC shall be made in the form of immediately available funds payable to PJMSettlement, or by wire transfer to a bank named by PJMSettlement.

(d) Payments by PJMSettlement. Unless delayed by unforeseen events, payments made by PJMSettlement, in its own name or as agent for the LLC, for amounts due to Members and other entities shall be paid no later than 5:00 p.m. Eastern Prevailing Time on the business day following the payment due date for net amounts owed to PJMSettlement, in its own name or as agent for the LLC, as specified above.

(e) Payment Calendar. A comprehensive billing and settlement calendar will be posted on the LLC's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

(f) Late Payments. In the event that a Member, or other entity, is delinquent in paying the amount set forth in its weekly or monthly bill two or more times within any rolling twelve (12) month period, PJMSettlement, in its own name or as agent for the LLC, may assess, in addition to the interest on each late payment as provided for in Section 7.2 of this Tariff, a late payment charge for a second and any subsequent failure to pay on time during such twelve (12) month period (a "Late Payment Charge"). The applicable Late Payment Charge will be assessed in an amount equal to the greater of: (i) two percent (2%) of the total amount set forth in the monthly or weekly bill that the Transmission Customer or other entity has been late in paying, or (ii) \$1,000; up to a maximum of \$100,000 per late bill payment. For the sole purpose of application of this Section 7.1A(f), weekly and monthly bills that are due on the same date shall be considered to be one bill; moreover, the term "on time" shall mean payment received on the date due; and "delinquent" shall mean any payment received on a day subsequent to the date due.

Late Payment Charges that are collected pursuant to this Section 7.1A(f) shall be credited to PJMSettlement administrative costs and will be included in any applicable stated rate refund calculations as contemplated under Schedule 9 of this Tariff.

14B.3 Interest on Unpaid Balances:

Interest on any unpaid amounts 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). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by PJMSettlement.

14B.4 Additional Billing and Payment Provisions With Respect to the Counterparty

(a) Each Member shall receive from PJMSettlement (and not from any other party), and shall pay to PJMSettlement (and not to any other party), the amounts specified in the PJM Tariff and this Agreement for services and transactions for which PJMSettlement is the Counterparty, and PJMSettlement shall be correspondingly obliged and entitled.

(b) **Payment netting.** If, during the settlement period, amounts in respect of obligations associated with transactions for which PJMSettlement are owed, and would otherwise be paid, by both a Member and PJMSettlement to each other, then the respective obligations to pay such amounts will automatically be cancelled and replaced by a single obligation upon the Member or PJMSettlement (as the case may be) that would have had to pay the larger aggregate amount to pay the net amount (if any) to the other.

(c) **Conditions for payment by the Counterparty.**

- (i) A Member shall be entitled to payment from PJMSettlement during the settlement period if, and only if, during the settlement period there is no amount in default due and payable by that Member to PJMSettlement with respect to transactions for which PJMSettlement is a Counterparty and not paid or recovered and so long as an amount in default, or any part of it, remains owing to PJMSettlement, that Member will not request, demand or claim to be entitled to payment by PJMSettlement.
- (ii) Subject to section 15, a defaulting Member shall be entitled to payment from PJMSettlement with respect to transactions for which PJMSettlement is the Counterparty, if, and only if, all amounts, liabilities and other obligations due, owing, incurred or payable by that defaulting Member to PJMSettlement or the LLC, whether those liabilities or obligations are actual or contingent, present or future, joint or several (including, without limitation, all interest (after as well as before judgment) and expenses) have been paid or recovered and until that time the defaulting Member will not request, demand or claim to be entitled to payment by PJMSettlement or the LLC.

(d) **Set-off.**

- (i) If during the settlement period an amount is due and, but for section 14B.4(c), would have been payable from PJMSettlement to a Member, but before that settlement period there was due from that Member an amount in default (as defined in section 15) that has not been paid or recovered, then notwithstanding section 14B.4(c), the amount owing by PJMSettlement shall be automatically and unconditionally set off against the amount(s) in default.

- (ii) If in respect of any non-paying Member there is more than one amount in default, then any amount due and payable from PJMSettlement shall be set off against the amounts in default in the order in which they originally became due and payable.
- (e) **Liability of PJMSettlement.**
 - (i) The liability of PJMSettlement to make payments during the settlement period shall be limited so that the aggregate of such payments does not exceed the aggregate amount of payments that has been paid to or recovered by PJMSettlement, from Members (including by way of realization of financial security) in respect of that settlement period.
 - (ii) Where in relation to any settlement period, the aggregate amount that PJMSettlement pays to Members with respect to transactions for which PJMSettlement is the Counterparty is less than the amount to which those Members, but for the operation of section 14B(e)(i), would have been entitled: if and to the extent that, after the required time during the settlement period, PJMSettlement or the LLC is paid and recovers (including collection of such amount through Default Allocation Assessments) amounts from any Member, PJMSettlement shall to the extent of such receipts make payments (to certain Members) in accordance with the provisions of section 15.2.1.

15. ENFORCEMENT OF OBLIGATIONS

15.1 Failure to Meet Obligations.

15.1.1 Termination of Market Buyer Rights.

The Office of the Interconnection shall terminate a Market Buyer's right to make purchases from the PJM Interchange Energy Market, the PJM Capacity Credit Market or any other market operated by PJM if it determines that the Market Buyer does not continue to meet the obligations set forth in this Agreement, including but not limited to the obligation to be in compliance with PJM's creditworthiness requirements and the obligation to make timely payment, provided that the Office of the Interconnection has notified the Market Buyer of any such deficiency and afforded the Market Buyer a reasonable opportunity to cure pursuant to Section 15.1.3. The Office of the Interconnection shall reinstate a Market Buyer's right to make purchases from the PJM Interchange Energy Market and PJM Capacity Credit Market upon demonstration by the Market Buyer that it has come into compliance with the obligations set forth in this Agreement.

15.1.2 Termination of Market Seller Rights.

The Office of the Interconnection shall not accept offers from a Market Seller that has not complied with the prices, terms, or operating characteristics of any of its prior scheduled transactions in the PJM Interchange Energy Market, unless such Market Seller has taken appropriate measures to the satisfaction of the Office of the Interconnection to ensure future compliance.

15.1.2A Close Out and Liquidation of Member Financial Transmission Rights

The Office of the Interconnection shall close out and liquidate all of a Member's current and forward Financial Transmission Rights positions if it determines the Member (i) no longer meets PJM's creditworthiness requirements, or (ii) fails to make timely payment when due under the PJM Operating Agreement or PJM Tariff, in each case following any opportunity given to cure the deficiency. Financial Transmission Rights shall be closed out and liquidated pursuant to Schedule 1, Section 7.3.9 of the PJM Operating Agreement and the Appendix to Attachment K, Section 7.3.9 of the PJM Tariff.

15.1.2A(1): Allocation of Costs and Proceeds Resulting from Liquidation

The liquidation of the defaulting Member's Financial Transmission Rights portfolio shall result in a final liquidated settlement amount. The final liquidated settlement amount may be aggregated with any other amounts owed by the defaulting Member to the Office of the Interconnection and may be set off by the Office of the Interconnection against any amounts owed by the Office of the Interconnection to the defaulting Member for purposes of determining the proper Default Allocation Assessment pursuant to the provisions of Section 15.2.2. Any payments made to a party purchasing some or all of a liquidated portfolio shall be net of that party's charge resulting from a Default Allocation Assessment.

15.1.3 Payment of Bills.

A Member shall make full and timely payment, in accordance with the terms specified by the Office of the Interconnection, of all bills rendered in connection with or arising under or from this Agreement, any service or rate schedule, any tariff, or any services performed by the Office of the Interconnection or transactions with PJMSettlement, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Member that fails to make full and timely payment to PJMSettlement (of amounts owed either directly to PJMSettlement or PJMSettlement as agent for the LLC) or otherwise fails to meet its financial or other obligations to a Member, PJMSettlement, or the LLC under this Agreement, shall, in addition to any requirement set forth in Section 15.1 and upon expiration of the 2-day period specified below be in default.

15.1.4 Breach Notification and Remedy

If the Office of the Interconnection concludes, upon its own initiative or the recommendation of or complaint by the Members Committee or any Member, that a Member is in breach of any obligation under this Agreement, including, but not limited to, the obligation to make timely payment and the obligation to meet PJM's creditworthiness standards and to otherwise comply with PJM's credit policies, the Office of the Interconnection shall so notify such Member. The notified Member may remedy such asserted breach by: (i) paying all amounts assertedly due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); and (ii) demonstration to the satisfaction of the Office of the Interconnection that the Member has taken appropriate measures to meet any other obligation of which it was deemed to be in breach; provided, however, that any such payment or demonstration may be subject to a reservation of rights, if any, to subject such matter to the PJM Dispute Resolution Procedures; and provided, further, that any such determination by the Office of the Interconnection may be subject to review by the PJM Board upon request of the Member involved or the Office of the Interconnection.

15.1.5 Default Notification and Remedy

If a Member has not remedied a breach by the 2nd business day following receipt of the Office of the Interconnection's notice, or receipt of the PJM Board's decision on review, if applicable, then the Member shall be in default and, in addition to such other remedies as may be available to the LLC or PJMSettlement:

- i) A defaulting Market Participant shall be precluded from buying or selling in the PJM Interchange Energy Market, the PJM Capacity Credit Market, or any other market operated by PJM until the default is remedied as set forth above;
- ii) A defaulting Member shall not be entitled to participate in the activities of any committee or other body established by the Members Committee or the Office of the Interconnection; and
- iii) A defaulting Member shall not be entitled to vote on the Members Committee or any other committee or other body established pursuant to this Agreement.

- iv) PJM shall notify all other members of the default.

15.1.6 Reinstatement of Member Following Default and Remedy

a. A Member that has been declared in default, solely of PJM's creditworthiness standards, or fails to otherwise comply with PJM's credit policies once within any 12 month period may be reinstated in full after remedying such default.

b. A Member that has been declared in default of this Agreement for failing to: (i) make timely payments when due once during any prior 12 month period, or (ii) adhere to PJM's creditworthiness standards and credit policies, twice during any prior 12 month period, may be subject to the following restrictions:

- a) Loss of stakeholder privileges, including voting privileges, for 12 months following such default; and
- b) Loss of the allowance of unsecured credit for 12 months following such default

c. A Member that has been declared in default of this Agreement for failing to: (i) make timely payments when due twice during any prior 12 month period, or (ii) adhere to PJM's creditworthiness standards and credit policies, three times during any prior 12 month period, shall, except as provided for below, not be eligible to be reinstated as a Member to this Agreement and its membership rights pursuant to this Agreement shall be terminated in accordance with Section 4.1(c) of this Agreement, notwithstanding whether such default has been remedied. Furthermore:

- a) PJMSettlement shall close out and liquidate all of the Member's current and forward positions in accordance with the provisions of this Agreement; and
- b) A Member terminated in accordance with these provisions shall be precluded from seeking future membership under this Agreement;

d. A Member may appeal a determination made pursuant to the foregoing procedures utilizing PJM's dispute resolution procedure as set forth in Schedule 5 of this Agreement, (provided, however, that a Member's decision to utilize these procedures shall not operate to stay the ability of PJM to exercise any and all of its rights under this Agreement and the PJM Tariff) and may be reinstated provided that the Member can demonstrate the following:

- a) that it has otherwise consistently complied with its obligations under this Agreement and the PJM Tariff; and
- b) the failure to comply was not material; and
- c) the failure to comply was due in large part to conditions that were not in the common course of business.

15.2 Enforcement of Obligations.

If the Office of the Interconnection sends a notice to the PJM Board that a Member has failed to perform an obligation under this Agreement, the PJM Board, on behalf of the LLC and PJMSettlement, shall initiate such action against such Member to enforce such obligation as the PJM Board shall deem appropriate. Subject to the procedures specified in Section 15.1, a Member's failure to perform such obligation shall be deemed to be a default under this Agreement. In order to remedy a default, but without limiting any rights the LLC or PJMSettlement may have against the defaulting Member, the PJM Board may assess against, and collect from, the Members not in default, in proportion to their Default Allocation Assessment, an amount equal to the amount that the defaulting Member has failed to pay to PJMSettlement or the LLC (less amounts covered by Financial Security, held by PJMSettlement, on behalf of itself and as agent for the LLC, or indemnifications paid to the LLC or PJMSettlement), along with appropriate interest. Such assessment shall in no way relieve the defaulting Member of its obligations. In addition to any amounts in default, the defaulting Member shall be liable to the LLC and PJMSettlement for all reasonable costs incurred in enforcing the defaulting Member's obligations.

15.2.1 Collection by the Office of the Interconnection.

PJMSettlement is authorized to pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims on behalf of the affected Members in the state and federal courts as well as under the United States Bankruptcy Code. Prior to initiating formal legal action in state or federal court to pursue collection, PJMSettlement shall provide to the Members Committee an explanation of its intended action. Upon the duly seconded motion of any Member, the Members Committee may conduct a vote to afford PJMSettlement a sense of the membership as regards to PJMSettlement's intended action to pursue collection. PJMSettlement shall consider any such vote before initiating formal legal action and at all times during the course of any collection effort evaluate the expected benefits in pursuing such effort in light of any changed circumstances. After deducting the costs of collection, any amounts recovered by PJMSettlement shall be distributed to the Members who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Member.

15.2.2 Default Allocation Assessment.

(a) "Default Allocation Assessment" shall be equal to $(0.1(1/N) + 0.9(A/Z))$, where:

N = the total number of Members, calculated as of five o'clock p.m. eastern prevailing time on the date PJM declares a Member in default, excluding ex officio Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under section 17.2 of this Agreement.

A = for Members comprising factor "N" above, the Member's gross activity as determined by summing the absolute values of the charges and credits for each of the Activity

Line Items identified in section 15.2.2(b) of this Agreement as accounted for and billed pursuant to section 3 of Schedule 1 of this Agreement for the month of default and the two previous months.

$Z =$ the sum of factor A for all Members excluding ex officio Members, State Consumer Advocates, Emergency and Economic Load Response Program Special Members, and municipal electric system Members that have been granted a waiver under section 17.2 of this Agreement.

The assessment value of $(0.1(1/N))$ shall not exceed \$10,000 per Member per calendar year, cumulative of all defaults. If one or more defaults arise that cause the value to exceed \$10,000 per Member, then the excess shall be reallocated through the gross activity factor.

(b) Activity Line Items shall be each of the line items on the PJM monthly bills net of load reconciliation adjustments and adjustments applicable to activity for the current billing month appearing on the same bill.

15.3 Obligations to a Member in Default.

The Members have no continuing obligation to provide the benefits of interconnected operations to a Member in default.

15.4 Obligations of a Member in Default.

A Member found to be in default shall take all possible measures to mitigate the continued impact of the default on the Members not in default, including, but not limited to, loading its own generation to supply its own load to the maximum extent possible.

15.5 No Implied Waiver.

A failure of a Member, the PJM Board, PJMSettlement, or the LLC to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such entity's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

15.6 Limitation on Claims.

(a) No claim seeking an adjustment in the billing for any service, transaction, or charge under this Agreement may be asserted with respect to a month, if more than two years has elapsed since the first date upon which the billing for that month occurred. PJMSettlement, on behalf of itself or as agent for PJM, may make no adjustment to billing with respect to a month for any service, transaction, or charge under this Agreement, if more than two years has elapsed since the first date upon which the billing for that month occurred, unless a claim seeking such adjustment had been received by PJMSettlement or PJM prior thereto.

(b) For claims that arose prior to the effective date of Section 15.6 of this Agreement, the claimant shall have two years from the effective date to assert such claims.

16. LIABILITY AND INDEMNITY

16.1 Members.

(a) As between the Members, except as may be otherwise agreed upon between individual Members with respect to specified interconnections, each Member will indemnify and hold harmless each of the other Members, and its directors, officers, employees, agents, or representatives, of and from any and all damages, losses, claims, demands, suits, recoveries, costs and expenses (including all court costs and reasonable attorneys' fees), caused by reason of bodily injury, death or damage to property of any third party, resulting from or attributable to the fault, negligence or willful misconduct of such Member, its directors, officers, employees, agents, or representatives, or resulting from, arising out of, or in any way connected with the performance of its obligations under this Agreement, excepting only, and to the extent, such cost, expense, damage, liability or loss may be caused by the fault, negligence or willful misconduct of any other Member. The duty to indemnify under this Agreement will continue in full force and effect notwithstanding the expiration or termination of this Agreement or the withdrawal of a Member from this Agreement, with respect to any loss, liability, damage or other expense based on facts or conditions which occurred prior to such termination or withdrawal.

(b) The amount of any indemnity payment arising hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Member seeking indemnification in respect of the indemnified action, claim, demand, costs, damage or liability. If any Member shall have received an indemnity payment for an action, claim, demand, cost, damage or liability and shall subsequently actually receive insurance proceeds or other amounts for such action, claim, demand, cost, damage or liability, then such Member shall pay to the Member that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

16.2 LLC Indemnified Parties.

(a) The LLC will indemnify and hold harmless the PJM Board, the LLC's officers, employees and agents, and any representatives of the Members serving on the Members Committee and any other committee created under Section 8 of this Agreement (all such Board Members, officers, employees, agents and representatives for purposes of this Section 16 being referred to as "LLC Indemnified Parties"), of and from any and all actions, claims, demands, costs (including consequential or indirect damages, economic losses and all court costs and reasonable attorneys' fees) and liabilities to any third parties, arising from, or in any way connected with, the performance of the LLC under this Agreement, or the fact that such LLC Indemnified Party was serving in such capacity, except to the extent that such action, claim, demand, cost or liability results from the willful misconduct of any LLC Indemnified Party with respect to participation in the misconduct. To the extent any dispute arises between any Member and the LLC arising from, or in any way connected with, the performance of the LLC under this Agreement, the Member and the LLC shall follow the PJM Dispute Resolution Procedures. To the extent that any such action, claim, demand, cost or liability arises from a Member's contractual or other obligation to provide electric service directly or indirectly to said third party, which obligation to provide service is limited by the terms of any tariff, service agreement, franchise, statute, regulatory requirement, court decision or other limiting provision, the Member designates the LLC and each LLC Indemnified Party a beneficiary of said limitation.

(b) An LLC Indemnified Party shall not be personally liable for monetary damages for any breach of fiduciary duty by such LLC Indemnified Party, except that an LLC Indemnified Party shall be liable to the extent provided by applicable law (i) for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law, or (ii) for any transaction from which the LLC Indemnified Party derived an improper personal benefit. Notwithstanding (i) and (ii), indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the LLC if and to the extent that the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses that such court shall deem proper. If applicable law is hereafter construed or amended to authorize the further elimination or limitation of the liability of LLC Indemnified Parties, then the liability of the LLC Indemnified Parties, in addition to the limitation on personal liability provided herein, shall be limited to the fullest extent permitted by law. No amendment to or repeal of this section shall apply to or have any effect on the liability or alleged liability of any LLC Indemnified Party or with respect to any acts or omissions occurring prior to such amendment or repeal. The termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which such person reasonably believed to be in or not opposed to the best interests of the LLC, and with respect to any criminal action or proceeding, had reasonable cause to believe that his or her conduct was unlawful.

(c) The LLC may pay expenses incurred by an LLC Indemnified Party in defending a civil, criminal, administrative or investigative action, suit or proceeding in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of

such LLC Indemnified Party to repay such amount if it shall ultimately be determined that such LLC Indemnified Party is not entitled to be indemnified by the LLC as authorized in this Section.

(d) In the event the LLC incurs liability under this Section 16.2 that is not adequately covered by insurance, such amounts shall be recovered pursuant to the PJM Tariff as provided in Schedule 3 of this Agreement.

16.3 Workers Compensation Claims.

Each Member shall be solely responsible for all claims of its own employees, agents and servants growing out of any Workers' Compensation Law.

16.4 Limitation of Liability.

No Member or its directors, officers, employees, agents, or representatives shall be liable to any other Member or its directors, officers, employees, agents, or representatives, whether liability arises out of contract, tort (including negligence), strict liability, or any other cause of or form of action whatsoever, for any indirect, incidental, consequential, special or punitive cost, expense, damage or loss, including but not limited to loss of profits or revenues, cost of capital of financing, loss of goodwill or cost of replacement power, arising from such Member's performance or failure to perform any of its obligations under this Agreement or the ownership, maintenance or operation of its System; provided, however, that nothing herein shall be deemed to reduce or limit the obligations of any Member with respect to the claims of persons or entities that are not parties to this Agreement.

16.5 Resolution of Disputes.

To the extent any dispute arises between one or more Members regarding any issue covered by this Agreement, the Members shall follow the dispute resolution procedures set forth in the PJM Dispute Resolution Procedures.

16.6 Gross Negligence or Willful Misconduct.

Neither PJMSettlement, the LLC, nor the LLC Indemnified Parties shall be liable to the Members or any of them, or to any third party or other person, for any claims, demands or costs arising from, or in any way connected with, the performance of PJMSettlement or the LLC under this Agreement other than actions, claims or demands based on gross negligence or willful misconduct; provided, however, that nothing herein shall limit or reduce the obligations of PJMSettlement or the LLC to the Members or any of them under the express terms of this Agreement or the PJM Tariff, including, but not limited to, those set forth in Sections 6.2 and 6.3 of this Agreement.

16.7 Insurance.

The PJM Board shall be authorized to procure insurance against the risks borne by the LLC and the LLC Indemnified Parties, the cost of which shall be treated as a cost and expense of the LLC.

17. MEMBER REPRESENTATIONS, WARRANTIES AND COVENANTS

17.1 Representations and Warranties.

Each Member makes the following representations and warranties to the LLC and each other Member, as of the Effective Date or such later date as such Member shall become admitted as a Member of the LLC.

17.1.1 Organization and Existence.

Such Member is an entity duly organized, validly existing and in good standing under the laws of the state of its organization.

17.1.2 Power and Authority.

Such Member has the full power and authority to execute, deliver and perform this Agreement and to carry out the transactions contemplated hereby.

17.1.3 Authorization and Enforceability.

The execution and delivery of this Agreement by such Member and the performance of its obligations hereunder have been duly authorized by all requisite action on the part of the Member, and do not conflict with any applicable law or with any other agreement binding upon the Member. The Agreement has been duly executed and delivered by such Member and constitutes the legal, valid and binding obligation of such Member, enforceable against it in accordance with the terms thereof, except insofar as such enforceability may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditors' rights generally, and to general principles of equity whether such principles are considered in proceedings in law or in equity.

17.1.4 No Government Consents.

No authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing with, any governmental authority is required for the execution, delivery and performance by such Member of this Agreement or the carrying out by such Member of the transactions contemplated hereby other than such authorization, consent, approval or order of, notice to or registration, qualification, declaration or filing that is pending before such governmental authority.

17.1.5 No Conflict or Breach.

None of the execution, delivery and performance by such Member of this Agreement, the compliance with the terms and provisions hereof and the carrying out of the transactions contemplated hereby, conflicts or will conflict with or will result in a breach or violation of any of the terms, conditions or provisions of any law, governmental rule or regulation or the charter documents or bylaws of such Member or any applicable order, writ, injunction, judgment or decree of any court or governmental authority against such Member or by which it or any of its properties, is bound, or any loan agreement, indenture, mortgage, bond, note, resolution, contract

or other agreement or instrument to which such Member is a party or by which it or any of its properties is bound, or constitutes or will constitute a default thereunder or will result in the imposition of any lien upon any of its properties.

17.1.6 No Proceedings.

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

17.2 Municipal Electric Systems.

Any provisions of Section 17.1 notwithstanding, if any Member that is a municipal electric system believes in good faith that the provisions of Sections 5.1(b) and 16.1 of this Agreement may not lawfully be applied to that Member under applicable state law governing municipal activities, the Member may request a waiver of the pertinent provisions of the Agreement. Any such request for waiver shall be supported by an opinion of counsel for the Member to the effect that the provision of the Agreement as to which waiver is sought may not lawfully be applied to the Member under applicable state law. The PJM Board shall have the right to have the opinion of the Member's counsel reviewed by counsel to the LLC. If the PJM Board concludes that either or both of Sections 5.1(b) and 16.1 of this Agreement may not lawfully be applied to a municipal electric system Member, it shall waive the application of the affected provision or provisions to such municipal Member. Any Member not permitted by law to indemnify the other Members shall not be indemnified by the other Members.

17.3 Survival.

All representations and warranties contained in this Section 17 shall survive the execution and delivery of this Agreement.

18. MISCELLANEOUS PROVISIONS

18.1 [Reserved.]

18.2 Fiscal and Taxable Year.

The fiscal year and taxable year of the LLC shall be the calendar year.

18.3 Reports.

Each year prior to the Annual Meeting of the Members, the PJM Board shall cause to be prepared and distributed to the Members a report of the LLC's activities since the prior report.

18.4 Bank Accounts; Checks, Notes and Drafts.

(a) Funds of the LLC shall be deposited in an account or accounts of a type, in form and name and in a bank(s) or other financial institution(s) which are participants in federal insurance programs as selected by the PJM Board. The PJM Board shall arrange for the appropriate conduct of such accounts. Funds may be withdrawn from such accounts only for bona fide and legitimate LLC purposes and may from time to time be invested in such short-term securities, money market funds, certificates of deposit or other liquid assets as the PJM Board deems appropriate. All checks or demands for money and notes of the LLC shall be signed by any officer or by any other person designated by the PJM Board.

(b) The Members acknowledge that the PJM Board may maintain LLC funds in accounts, money market funds, certificates of deposit, other liquid assets in excess of the insurance provided by the Federal Deposit Insurance Corporation, or other depository insurance institutions and that the PJM Board shall not be accountable or liable for any loss of such funds resulting from failure or insolvency of the depository institution.

(c) Checks, notes, drafts and other orders for the payment of money shall be signed by such persons as the PJM Board from time to time may authorize. When the PJM Board so authorizes, the signature of any such person may be a facsimile.

18.5 Books and Records.

(a) At all times during the term of the LLC, the PJM Board shall keep, or cause to be kept, full and accurate books of account, records and supporting documents, which shall reflect, completely, accurately and in reasonable detail, each transaction of the LLC. The books of account shall be maintained and tax returns prepared and filed on the method of accounting determined by the PJM Board. The books of account, records and all documents and other writings of the LLC shall be kept and maintained at the principal office of the Interconnection.

(b) The PJM Board shall cause the Office of the Interconnection to keep at its principal office the following:

- i) A current list in alphabetical order of the full name and last known business address of each Member and the Members Committee sector of each Voting Member;
- ii) A copy of the Certificate of Formation and the Certificate of Conversion, and all Certificates of Amendment thereto;
- iii) Copies of the LLC's federal, state, and local income tax returns and reports, if any, for the three most recent years; and
- iv) Copies of the Operating Agreement, as amended, and of any financial statements of the LLC for the three most recent years.

18.6 Amendment.

(a) Except as provided by law or otherwise set forth herein, this Agreement, including any Schedule hereto, may be amended, or a new Schedule may be created, only upon: (i) submission of the proposed amendment to the PJM Board for its review and comments; (ii) approval of the amendment or new Schedule by the Members Committee, after consideration of the comments of the PJM Board, in accordance with Section 8.4, or written agreement to an amendment of all Members not in default at the time the amendment is agreed upon; and (iii) approval and/or acceptance for filing of the amendment by FERC and any other regulatory body with jurisdiction thereof as may be required by law. If and as necessary, the Members Committee may file with FERC or other regulatory body of competent jurisdiction any amendment to this Agreement or to its Schedules or a new Schedule not filed by the Office of the Interconnection.

(b) Notwithstanding the foregoing, an applicant eligible to become a Member in accordance with the procedures specified in this Agreement shall become a Member by executing a counterpart of this Agreement without the need for amendment of this Agreement or execution of such counterpart by any other Member.

(c) Each of the following fundamental changes to the LLC shall require or be deemed to require an amendment to this Agreement and shall require the prior approval of FERC:

- i) Adoption of any plan of merger or consolidation;
- ii) Adoption of any plan of sale, lease or exchange of assets relating to all, or substantially all, of the property and assets of the LLC;
- iii) Adoption of any plan of division relating to the division of the LLC into two or more corporations or other legal entities;
- iv) Adoption of any plan relating to the conversion of the LLC into a stock corporation;
- v) Adoption of any proposal of voluntary dissolution; or
- vi) Taking any action which has the purpose or effect of the adoption of any plan or proposal described in items (i), (ii), (iii), (iv) or (v) above.

18.7 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.8 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

18.9 Catastrophic Force Majeure.

Performance of any obligation arising under this Agreement, owed by a Member to either PJM or to another Member (either directly or indirectly), shall not be excused or suspended by reason of an event of force majeure unless such event constitutes an event of Catastrophic Force Majeure. An event of Catastrophic Force Majeure shall excuse a Member from performing obligations arising under this Agreement during the period such Member's performance is prevented by any event of Catastrophic Force Majeure, provided such event was not caused by such Member's fault or negligence. An event of Catastrophic Force Majeure may suspend but shall not excuse any payment obligation owed by a Member. Any excuse or exception to a performance obligation expressly provided for by specific terms of this Agreement, the PJM Tariff, or the Reliability Assurance Agreement shall apply according to their terms and remain in full force and effect without regard to this provision. Unless expressly referenced in any section of this Agreement, the PJM Tariff, or the Reliability Assurance Agreement, this provision shall not apply, and not supersede, other force majeure provisions that are expressly applicable to specific obligations arising under any sections of those documents. This provision shall apply in its entirety to all rules, rights and obligations specified in Attachment K-Appendix of the PJM Tariff, Attachment DD of the PJM Tariff, Schedule 1 of the Operating Agreement, and the Reliability Assurance Agreement. Other than this provision, no other force majeure provisions in this Agreement, the PJM Tariff, or the Reliability Assurance Agreement shall apply in any manner to Attachment K-Appendix of the PJM Tariff, Attachment DD of the PJM Tariff, Schedule 1 of the Operating Agreement, and the Reliability Assurance Agreement.

18.10 Further Assurances.

Each Member hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

18.11 Seal.

The seal of the LLC shall have inscribed thereon the name of the LLC, the year of its organization and the words “Corporate Seal, Delaware.” The seal may be used by causing it or a facsimile thereof to be impressed or affixed or reproduced or otherwise.

18.12 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 all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

18.13 Costs of Meetings.

Each Member shall be responsible for all costs of its representative, alternate or substitute in attending any meeting. The Office of the Interconnection shall pay the other reasonable costs of meetings of the PJM Board and the Members Committee, and such other committees, subcommittees, task forces, working groups, User Groups or other bodies as determined to be appropriate by the Office of the Interconnection, which costs otherwise shall be paid by the Members attending. The Office of the Interconnection shall reimburse all Board Members for their reasonable costs of attending meetings.

18.14 Notice.

(a) Except as otherwise expressly provided herein, notices required under this Agreement shall be in writing and shall be sent to a Member by overnight courier, hand delivery, telecopier or other reliable electronic means to the representative on the Members Committee of such Member at the address for such Member previously provided by such Member to the Office of the Interconnection. Any such notice so sent shall be deemed to have been given (i) upon delivery if given by overnight couriers or hand delivery, or (ii) upon confirmation if given by telecopier or other reliable electronic means. Notices of meetings of the Members Committee or committees, subcommittees, task forces, working groups and other bodies under its auspices may be given as provided in the Members Committee by-laws.

(b) Notices, as well as copies of the agenda and minutes of all meetings of committees, subcommittees, task forces, working groups, User Groups, or other bodies formed under this Agreement, shall be posted in a timely fashion on and made available for downloading from the PJM website.

18.15 Headings.

The section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

18.16 No Third-Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Members and their respective successors and permitted assigns and, unless expressly stated herein, is not intended to and shall not confer any rights or benefits on any third party (other than successors and permitted assigns) not a signatory hereto.

18.17 Confidentiality.

18.17.1 Party Access.

(a) No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection and/or the PJM Market Monitor or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

(b) Except as may be provided in this Agreement or in the PJM Open Access Transmission Tariff, the Office of the Interconnection shall not disclose to its Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Office of the Interconnection or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Office of the Interconnection from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality; provided further that nothing contained herein shall prohibit the Office of the Interconnection from providing Member confidential information to the NERC, any Applicable Regional Entity, or to any reliability coordinator, to the extent that (i) the Office of the Interconnection determines in its reasonable discretion that the exchange of such information is required to enhance and/or maintain reliability within the Members' Applicable Regional Entities and their neighboring Regional Entities, or within the region of any reliability coordinator, (ii) such entity is bound by a written agreement to maintain such confidentiality, and (iii) the Office of the Interconnection has notified the affected party of its intention to release such information no less than five business days prior to the release. The Office of the Interconnection, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this Section 18.17. Nothing contained herein shall prohibit the Office of the Interconnection or its designated agents, representatives, or contractors from providing to another Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such RTO or ISO has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such RTO or ISO is bound by a tariff provision requiring that the e-Tag data be maintained as confidential or, in the absence of a tariff requirement governing confidentiality, a written agreement with the Office of the Interconnection consistent with FERC Order No. 771 and any clarifying orders and implementing regulations. The Office of the Interconnection shall collect and use confidential information only in connection with its authority under this Agreement and the Open Access

Transmission Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

(c) Nothing contained herein shall prevent the Office of the Interconnection from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Office of the Interconnection and/or the PJM Market Monitor specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Office of the Interconnection shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Office of the Interconnection, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

(d) Reciprocal provisions to Sections 18.17.1, 18.17.2, 18.17.3, 18.17.4 and 18.17.5 hereof, delineating the confidentiality requirements of PJM's Market Monitoring Unit, are set forth in Attachment M – Appendix, section I.

(e) Notwithstanding anything to the contrary in this Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation on the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection. However, to protect the confidential, market sensitive and/or proprietary bidding strategies of Market Participants as well as the identity of Market Participants from being discernible from the published data, the posted information will not reveal the (a) name of the resource, (b) characteristics of a specific resource, (c) identity of the load, (d) name of the individual or entity submitting the data, (e) identity of the resource owner, or (f) location of the resource at a level lower than its Zone. The Office of the Interconnection also reserves the right to take any other precautionary measures that it deems appropriate to preserve the confidential, market sensitive and/or proprietary bidding strategies of Market Participants to the extent not specifically set forth herein.

(f) To the extent permitted pursuant to 18 C.F.R. § 38.2 (or successor provisions), nothing contained herein shall prohibit the Office of the Interconnection from sharing non-public, operational information with an interstate natural gas pipeline operator for the purpose of promoting reliable service or operational planning. Further, the Office of the Interconnection shall be permitted to share non-public, operational information with natural gas local distribution companies and/or intrastate natural gas pipeline operators, as appropriate, for the purpose of promoting reliable service or operational planning, provided that such party has acknowledged, in writing, that it *shall not disclose*, or use anyone as a conduit for disclosure of, non-public, operational information received from the Office of Interconnection to a third party or *in an unduly discriminatory or preferential manner or to the detriment of any natural gas and/or electric market*. Such non-public, operational information received from natural gas local distribution companies and/or intrastate natural gas pipeline operators pursuant to this section

will be subject to the confidentiality provisions set forth in this Section 18.17 of the Operating Agreement.

18.17.2 Required Disclosure.

(a) Notwithstanding anything in the foregoing Section to the contrary, and subject to the provisions of Section 18.17.3, if the Office of the Interconnection is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection or its designated agents, representatives, or contractors may make disclosure of such information; provided, however, that as soon as the Office of the Interconnection learns of the disclosure requirement and prior to it or its designated agents, representatives, or contractors making disclosure, the Office of the Interconnection shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Office of the Interconnection shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Office of the Interconnection shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(b) Nothing in this Section 18.17 shall prohibit or otherwise limit the Office of the Interconnection's use of information covered herein if such information was: (i) previously known to the Office of the Interconnection without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection using non-confidential information; (iii) acquired by the Office of the Interconnection from a third party which is not, to the Office of the Interconnection's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this Section 18.17.

(c) The Office of the Interconnection shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Agreement or of the Open Access Transmission Tariff a contractual duty of confidentiality consistent with this Agreement. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Office of the Interconnection shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

18.17.3 Disclosure to FERC and CFTC.

(a) Notwithstanding anything in this Section to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC"), or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Office of the Interconnection that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection shall provide the requested information to the FERC, CFTC or their respective staff, within the time provided for in the request for information. In providing the information to

the FERC or its staff, the Office of the Interconnection may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Office of the Interconnection may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Office of the Interconnection shall promptly notify any affected Member(s) if the Office of the Interconnection receives from the FERC, CFTC or their staff written notice that the commission has decided to release publicly, or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission by the Office of the Interconnection.

(b) Section 18.17.3(a) shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection shall follow the procedures in Section 18.17.2.

(c) Pursuant to the FERC Order No. 760, as codified under 18 C.F.R. § 35.28(g)(4), to the extent that the Office of the Interconnection already collects such data described in Order No. 760, the Office of the Interconnection shall electronically deliver to the FERC, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the FERC, data related to the markets that the Office of the Interconnection administers. Section 18.17.3(a) shall not apply to data supplied to the FERC under this subsection (c) to satisfy the FERC Order No. 760 requirements.

(d) Pursuant to the FERC Order No. 771 and any clarifying orders, as codified under 18 C.F.R. § 366.2(d), the Office of the Interconnection shall ensure that FERC is included as an addressee on all e-Tags for transactions that sink within the PJM Region.

18.17.4 Disclosure to Authorized Commissions.

(a) Notwithstanding anything in this section to the contrary, the Office of the Interconnection shall disclose confidential information, otherwise required to be maintained in confidence pursuant to this Agreement, to an Authorized Commission under the following conditions:

- (i) The Authorized Commission has provided the FERC with a properly-executed Certification in the form attached hereto as Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the Commission within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a FERC protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the Commission, the

Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the Commission as set forth above in this paragraph.

The Office of the Interconnection may not disclose data to an Authorized Commission during the Commission's consideration of the Certification and any filed protests. If the Commission does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section. In the event that an interested party protests the Authorized Commission's Certification and the Commission approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

- (ii) Any confidential information provided to an Authorized Commission pursuant to this section shall not be further disclosed by the recipient Authorized Commission except by order of the Commission.
- (iii) The Office of the Interconnection shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.
- (iv) The Authorized Commission may provide confidential information obtained from the Office of the Interconnection to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the PJM Market Monitor and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a non-disclosure agreement in the form attached hereto as Schedule 10 before being provided access to any such confidential information.

- (v) The Office of the Interconnection shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on its website, or by written request. Such schedule shall be compiled by the Office of the Interconnection, based on information provided by any Authorized Commission. The Office of the Interconnection shall update the schedule promptly upon receipt of information from an Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Office of the Interconnection in the compilation and/or maintenance of the schedule.

(b) The Office of the Interconnection may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Office of the Interconnection will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section 18.17.4(b). In any such discussions, the Office of the Interconnection shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Office of the Interconnection shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Office of the Interconnection shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) business day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) business days of the initial oral disclosure.

(c) As regards Information Requests:

- (i) Information Requests to the Office of the Interconnection and/or PJM Market Monitor by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Office of the Interconnection, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Office of the Interconnection shall provide an Affected Member with written notice, which shall include electronic

communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) business days after the receipt of the Information Request.

- (ii) Subject to the provisions of section (c)(iii), the Office of the Interconnection shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) business days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) business day without the express consent of the Affected Member. To the extent that the Office of the Interconnection cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Office of the Interconnection shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Office of the Interconnection shall not reveal any Member's confidential information to any other Member.
- (iii) Notwithstanding section (c)(ii), above, should the Office of the Interconnection or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) business days following the Office of the Interconnection's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection or the Affected Member may file a complaint with the Commission pursuant to Rule 206 objecting to the Information Request within ten (10) business days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of

a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or PJM Market Monitor workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Office of the Interconnection and/or the PJM Market Monitor. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Office of Interconnection shall use its best efforts to respond to the Information Request promptly.

- (iv) Any Authorized Commission may initiate appropriate legal action at FERC within ten (10) business days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

(d) In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

- (i) The Authorized Commission or Authorized Person shall promptly notify the Office of the Interconnection, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section.
- (ii) The Office of the Interconnection shall terminate the right of such Authorized Commission to receive confidential information under this

section upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Office of the Interconnection's and/or the PJM Market Monitor's actions under this section shall be to FERC. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section 18.17.4(a) by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's re-certification filing with sixty (60) days of the date of the filing, the re-certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

- (iii) The Office of the Interconnection and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Office of the Interconnection.
- (iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this Section (d)(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.
- (v) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.5 Disclosure to New York ISO and New York ISO Market Advisor Concerning Facilities in PSE&G Zone.

- (a) Subject to the requirements of section 18.17.5(b), the Office of the Interconnection may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential

information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of the New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or its Market Monitoring Unit determines necessary to carry out the responsibilities of the Office of the Interconnection, the New York ISO and the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

(b) The Office of the Interconnection may release a Member's confidential information pursuant to section 18.17.5(a) to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this section 18.17. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under section 18.17.5(a) that is designated as confidential shall be protected from disclosure in accordance with this section 18.17.

18.17.6 Disclosure of EMS Data to Transmission Owners on PJM EMS Terminal

(a) While the Office of the Interconnection has overall power system reliability in the Office of the Interconnection region, Transmission Owners within the Office of the Interconnection region perform certain reliability functions with respect to their individual Transmission Facilities and distribution systems. In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, install a read-only terminal in any Transmission Owner's secure control room facility, with access to Office of the Interconnection's Energy Management System (EMS) and its associated data transmission and generation data under the terms and conditions set forth in this section 18.17.6.

(b) The data and information produced by the Office of the Interconnection's EMS are confidential and/or commercially sensitive because it will display the real-time status of electric transmission lines and generation facilities, the disclosure of which could impact the market and the commercial interests of its participants. In addition, the responsive information will contain detailed information about real-time grid conditions, transmission lines, power flows, and outages, which may fall within the definition of Critical Energy Infrastructure Information (CEII) as set forth in 18 CFR § 388.112. The Office of the Interconnection shall not release any generator cost, price or other market information without written authorization pursuant to section § 18.17.1 (c) supra unless otherwise provided for under this Agreement. The only generator information that will be made available on the read-only PJM EMS terminal is real-time MW/MVAR output and Minimum/Maximum MW Range.

(c) The confidential or CEII information provided to the Transmission Owner on a read-only PJM EMS terminal shall only be held in the secure control room facility of the Transmission Owner. Such data shall be used for informational and operational purposes within the control room by Transmission Function employees as defined in the FERC's rules and regulations, 18 C.F.R. § 358.3 (j). No "screen-scraping" or other data transfer of information from the read-only terminal to other Transmission Owner systems or databases shall be permitted. No storage of information from the read-only terminal shall be permitted. The data shall be held confidential within the transmission function environment and not be disclosed to other personnel within the Transmission Owners' company, subsidiaries, marketing organizations, energy affiliates or independent third parties. The Transmission Owner may use the confidential or CEII information only for the purpose of performing Transmission Owner's reliability function and shall not otherwise use the confidential information for its own benefit or for the benefit of any other person.

(d) In the event of any breach:

- (i) The Transmission Owners shall promptly notify the Office of the Interconnection, which shall, in turn, promptly notify FERC and any Affected Member(s) of any inadvertent or intentional release, or possible release, of confidential or CEII information disclosed as provided above.
- (ii) The Office of the Interconnection shall terminate all rights of the Transmission Owner to receive confidential or CEII information as provided in this section 18.17.6; provided, however, that the Office of the Interconnection may restore a Transmission Owners' status after consulting with the Affected Member(s) and to the extent that: (a) the Office of the Interconnection determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (b) there were no harm or damages suffered by the Affected Member(s); or (c) similar good cause shown. Any appeal of the Office of the Interconnection's actions under this section shall be to FERC.
- (iii) The Office of the Interconnection and/or the Affected Member(s) shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief and/or damages with respect to any breach; and (c) the immediate return of all confidential or CEII information to the Office of the Interconnection.
- (iv) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(b) and (c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.7 Disclosure of Generator Data to Transmission Owners

(a) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner upon the Transmission Owner's request the following confidential generator information for any generator that: (1) is or will be modeled within the Transmission Owner's energy management system; or (2) is providing Black Start Service to the Transmission Owner:

- (i) real-time unit status;
- (ii) real-time megawatt output;
- (iii) real-time megavolt amperes reactive ("MVAR");
- (iv) the start date, start time, stop date, and stop time for the unit's scheduled outages; and
- (v) the unit's reactive capability curve.

The Office of the Interconnection will provide such data only where it possesses such data. The Office of the Interconnection shall provide this confidential information only to transmission function employees, as transmission function employee is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(b) A Transmission Owner may only use the generator data provided under section 18.17.7(a) above for the purpose of executing the Transmission Owner's reliability function and transmission function, as transmission function is defined in section 18 C.F.R. § 358 of the FERC rules and regulations, and shall not otherwise use the confidential information for its own benefit or the benefit of any other person. A Transmission Owner may disclose the generator data obtained under section 18.17.7(a) above only to the Transmission Owner's transmission function employees whose access to such data is necessary to perform the Transmission Owner's transmission functions. Transmission Owners shall not disclose the generator data obtained under section 18.17.7(a) above to any person, including marketing function employees as defined in section 18 C.F.R. § 358 of the FERC rules and regulations, except as permitted under this section 18.17.7 of this Agreement.

(c) Each Transmission Owner shall protect and keep confidential all the information it receives from the Office of the Interconnection pursuant to this section 18.17.7. It may, copy, post, distribute, disclose or disseminate the data obtained pursuant to section 18.17.7(a) above only in the following manner. Each Transmission Owner may make a limited number of copies of written or electronic materials to enable the Transmission Owner to adequately use the information obtained pursuant to section 18.17.7(a) above within the terms and conditions of this section of this Agreement. If the Transmission Owner prints or electronically conveys any information in obtained pursuant to section 18.17.7(a) above, it shall protect each copy in accordance with this section 18.17.7 and mark each copy as "Confidential Information."

(d) The Transmission Owner shall destroy all information obtained under section 18.17.7(a) above upon the completion of the use of such information for the purpose of performing Transmission Owner's transmission functions, as transmission functions is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(e) A Transmission Owner shall be responsible for the breach of this section 18.17.7 by any of its employees or representatives. In the event of any breach by the Transmission Owner of this section 18.17.7 by any of its employees or representatives, section 18.17.6(d) shall apply to the release of the confidential information.

18.18 Termination and Withdrawal.

18.18.1 Termination.

Upon termination of this Agreement, final settlement for obligations under this Agreement shall include the accounting for the period ending with the last day of the last month for which the Agreement was effective.

18.18.2 Withdrawal.

Subject to the requirements of Section 4.1(c) of this Agreement and Section 1.4.6 of the Schedule 1 to this Agreement, any Member may withdraw from this Agreement upon 90 days notice to the Office of the Interconnection.

18.18.3 Winding Up.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination or expiration of this Agreement shall survive such termination or expiration. The surviving provisions shall include, but shall not be limited to: (i) those provisions necessary to permit the orderly conclusion, or continuation pursuant to another agreement, of transactions entered into prior to the decision to terminate this Agreement, (ii) those provisions necessary to conduct final billing, collection, and accounting with respect to all matters arising hereunder, and (iii) the indemnification provisions as applicable to periods prior to such termination or expiration.

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

RESOLUTION REGARDING ELECTION OF DIRECTORS

1. Subject to the approval of the Federal Energy Regulatory Commission, the provisions of Section 7.1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (the "Operating Agreement"), to the extent that such section requires that the election of members to the PJM Board of Managers be held at the Annual Meeting of the Members, be, and they hereby are, waived, solely for election to those positions on the PJM Board of Managers that expire in the year 2001; and
2. An election of members of the PJM Board of Managers from the slate approved by the independent consultant retained by the Office of the Interconnection, is, and hereby shall be, authorized by the PJM Members Committee to occur at its meeting held on August 30, 2001; and
3. The Office of the Interconnection is, and hereby shall be, authorized to file such documents and make such pleadings before the Federal Energy Regulatory Commission as the Office of the Interconnection determines to be reasonably necessary seeking such waivers and authorizations as may be required to assure the validity of the aforementioned election of members to the PJM Board of Managers.

SCHEDULE 1
PJM INTERCHANGE ENERGY MARKET

References to section numbers in this Schedule 1 refer to sections of this Schedule 1, unless otherwise specified.

1. MARKET OPERATIONS

1.1 Introduction.

This Schedule sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the PJM Interchange Energy Market within the PJM Region. This Schedule addresses each of the three time-frames pertinent to the daily operation of the PJM Interchange Energy Market: Prescheduling, Scheduling, and Dispatch. This schedule also addresses the settlement of transactions in the single PJM Interchange Energy Market at two component settlement prices: Day-Ahead prices and Real-Time prices.

1.2 Cost-based Offers.

Unless and until the FERC shall authorize the use of market-based prices in the PJM Interchange Energy Market, all offers for energy or other services to be sold on the PJM Interchange Energy Market from generating resources located within the PJM Region shall not exceed the variable cost of producing such energy or other service, as determined in accordance with Schedule 2 to this Agreement and applicable regulatory standards, requirements and determinations; provided that, a Market Seller may offer to the PJM Interchange Energy Market the right to call on energy from a resource the output of which has been sold on a bilateral basis, with the rate for such energy if called equal to the curtailment rate specified in the bilateral contract.

1.2A Transmission Losses.

1.2A.1 Description of Transmission Losses.

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines and other transmission facilities.

1.2A.2 Inclusion of Transmission Losses.

Whenever in this Schedule 1, transmission losses are included in the determination of a charge, credit, load (including deviations), or demand reduction, it is explicitly so stated and such included losses shall be those losses incurred on all Transmission Facilities (to facilitate such calculation, Transmission Owners shall ensure that all such facilities are included in the PJM network model) and those losses incurred on generator step-up transformers that a Market Seller has not elected to remove from the loss calculation. Absent such explicit statement, such losses are not included in the determination.

1.2A.3 Other Losses.

Losses incurred on facilities other than those addressed in the preceding section may be included in the determination of charges, credits, load (including real-time deviations) or demand reductions, as determined by electric distribution companies, unless this Schedule explicitly excludes such losses.

1.3 [Reserved for Future Use]

1.4 Market Buyers.

1.4.1 Qualification.

- (a) To become a Market Buyer, an entity shall submit an application to the Office of the Interconnection, in such form as shall be established by the Office of the Interconnection.
- (b) An applicant that is a Load Serving Entity or that will purchase on behalf of or for ultimate delivery to a Load Serving Entity shall establish to the satisfaction of the Office of the Interconnection that the end-users that will be served through energy and related services purchased in the PJM Interchange Energy Market, are located electrically within the PJM Region, or will be brought within the PJM Region prior to any purchases from the PJM Interchange Energy Market. Such applicant shall further demonstrate that:
 - i) The Load Serving Entity for the end users is obligated to meet the requirements of the Reliability Assurance Agreement; and
 - ii) The Load Serving Entity for the end users has arrangements in place for Network Transmission Service or Point-To-Point Transmission Service for all PJM Interchange Energy Market purchases.
- (c) An applicant that is not a Load Serving Entity or purchasing on behalf of or for ultimate delivery to a Load Serving Entity shall demonstrate that:
 - i) The applicant has obtained or will obtain Network Transmission Service or Point-to-Point Transmission Service for all PJM Interchange Energy Market purchases; and
 - ii) The applicant's PJM Interchange Energy Market purchases will ultimately be delivered to a load in another Control Area that is recognized by NERC and that complies with NERC's standards for operating and planning reliable bulk electric systems.
- (d) An applicant shall not be required to obtain transmission service for purchases from the PJM Interchange Energy Market to cover quantity deviations from its sales in the Day-ahead Energy Market.
- (e) All applicants shall demonstrate that:
 - i) The applicant is capable of complying with all applicable metering, data storage and transmission, and other reliability, operation, planning and accounting standards and requirements for the operation of the PJM Region and the PJM Interchange Energy Market;
 - ii) The applicant meets the creditworthiness standards established by the Office of the Interconnection, or has provided a letter of credit or other form of

security acceptable to the Office of the Interconnection; and

iii) The applicant has paid all applicable fees and reimbursed the Office of the Interconnection for all unusual or extraordinary costs of processing and evaluating its application to become a Market Buyer, and has agreed in its application to subject any disputes arising from its application to the PJM Dispute Resolution Procedures.

(f) The applicant shall become a Market Buyer upon a final favorable determination on its application by the Office of the Interconnection as specified below, and execution by the applicant of counterparts of this Agreement.

1.4.2 Submission of Information.

The applicant shall furnish all information reasonably requested by the Office of the Interconnection in order to determine the applicant's qualification to be a Market Buyer. The Office of the Interconnection may waive the submission of information relating to any of the foregoing criteria, to the extent the information in the Office of the Interconnection's possession is sufficient to evaluate the application against such criteria.

1.4.3 Fees and Costs.

The Office of the Interconnection shall require all applicants to become a Market Buyer to pay a uniform application fee, initially in the amount of \$1,500, to defray the ordinary costs of processing such applications. The application fee shall be revised from time to time as the Office of the Interconnection shall determine to be necessary to recover its ordinary costs of processing applications. Any unusual or extraordinary costs incurred by the Office of the Interconnection in processing an application shall be reimbursed by the applicant.

1.4.4 Office of the Interconnection Determination.

Upon submission of the information specified above, and such other information as shall reasonably be requested by the Office of the Interconnection, the Office of the Interconnection shall undertake an evaluation and investigation to determine whether the applicant meets the criteria specified above. As soon as practicable, but in any event not later than 60 days after submission of the foregoing information, or such later date as may be necessary to satisfy the requirements of the Reliability Assurance Agreement, the Office of the Interconnection shall notify the applicant and the members of the Members Committee of its determination, along with a written summary of the basis for the determination. The Office of the Interconnection shall respond promptly to any reasonable and timely request by a Member for additional information regarding the basis for the Office of the Interconnection's determination, and shall take such action as it shall deem appropriate in response to any request for reconsideration or other action submitted to the Office of the Interconnection not later than 30 days from the initial notification to the Members Committee.

1.4.5 Existing Participants.

Any entity that was qualified to participate as a Market Buyer in the PJM Interchange Energy Market under the Operating Agreement of PJM Interconnection L.L.C. in effect immediately prior to the Effective Date shall continue to be qualified to participate as a Market Buyer in the PJM Interchange Energy Market under this Agreement.

1.4.6 Withdrawal.

- (a) An Internal Market Buyer that is a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal not earlier than the effective date of (i) its withdrawal from the Reliability Assurance Agreement, or (ii) the assumption of its obligations under the Reliability Assurance Agreement by an agent that is a Market Buyer.
- (b) An External Market Buyer or an Internal Market Buyer that is not a Load Serving Entity may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice.
- (c) Withdrawal from this Agreement shall not relieve a Market Buyer of any obligation to pay for electric energy or related services purchased from the PJM Interchange Energy Market prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions or events occurring prior to such withdrawal; and provided, further, that withdrawal from this Agreement shall not relieve any Market Buyer of any obligations it may have under, or constitute withdrawal from, any other Related PJM Agreement.
- (d) A Market Buyer that has withdrawn from this Agreement may reapply to become a Market Buyer in accordance with the provisions of this Section 1.4, provided it is not in default of any obligation incurred under this Agreement.

1.5 Market Sellers.

1.5.1 Qualification.

A Member that demonstrates to the Office of the Interconnection that the Member meets the standards for the issuance of an order mandating the provision of transmission service under section 211 of the Federal Power Act, as amended by the Energy Policy Act of 1992, may become a Market Seller upon execution of this Agreement and submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule. All Members that are Market Buyers shall become Market Sellers upon submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule.

1.5.2 Withdrawal.

(a) A Market Seller may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice; provided, however, that withdrawal shall not relieve a Market Seller of any obligation to deliver electric energy or related services to the PJM Interchange Energy Market pursuant to an offer made prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by PJMSettlement, on behalf of itself or the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such withdrawal; and provided, further, that withdrawal shall not relieve any entity that is a Market Seller and is also a Market Buyer of any obligations it may have as a Market Buyer under, or constitute withdrawal as a Market Buyer from, this Agreement or any other Related PJM Agreement.

(b) A Market Seller that has withdrawn from this Agreement may reapply to become a Market Seller at any time, provided it is not in default with respect to any obligation incurred under this Agreement.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of Section 1.5A.10.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in section 1.4.3 of this Agreement; (ii) liability under section 15.2 of this Agreement for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such

registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten business days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type

of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten business days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten business days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority

permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of section 1.5A, including section 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service

Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
 - b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
 - c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
 - d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Independent Market Monitor and/or the Federal Energy Regulatory Commission Office of Enforcement.
- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits

applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by sections 3.3A.2 and 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Demand Resource Provision of Synchronized Reserve or Day-ahead Scheduling Reserves.

- (a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Demand Resource” pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.
- (b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.
- (c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection’s dispatch instruction associated with a Synchronized Reserve Event, or as

applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under section 3.3A.5 and 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day- Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.5 and 3.3A.6;
- v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

- vi. Each End-Use Customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and
- vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by a demand resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

- (a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.
- (b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

The Office of the Interconnection shall operate the PJM Interchange Energy Market in accordance with this Agreement.

1.6.2 Scope of Services.

The Office of the Interconnection shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including but not limited to the following:

- i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Operating Agreement, and the Schedules to this Agreement;
- ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;
- iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;
- iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;
- v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;
- vi) Administer (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;
- vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Entity principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;
- viii) Protect confidential information as specified in this Agreement; and

ix) Send a representative to meetings of the Members Committee or other Committees, subcommittees, or working groups specified in this Agreement or formed by the Members Committee when requested to do so by the chair or other head of such committee or other group;

and

x) Coordinate with adjacent Control Areas on Coordinated Transaction Scheduling (“CTS”) and forecast price calculations, in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.6.3 Records and Reports.

The Office of the Interconnection shall prepare and maintain such records and prepare such reports, including, but not limited to quarterly budget reports, as are required to document the performance of its obligations to the Market Participants hereunder in a form adopted by the Office of the Interconnection upon consideration of the advice and recommendations of the Members Committee. The Office of the Interconnection shall also produce special reports reasonably requested by the Members Committee and consistent with FERC’s standards of conduct; provided, however, the Market Participants shall reimburse the Office of the Interconnection for the costs of producing any such report. Notwithstanding the foregoing, the Office of the Interconnection shall not be required to disclose confidential or commercially sensitive information in any such report.

1.6.4 PJM Manuals.

The Office of the Interconnection shall prepare, maintain and update the PJM Manuals consistent with this Agreement. The PJM Manuals shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the LLC or any Member, and the public.

1.6A PJMSettlement

1.6A.1 Scope of Services

PJMSettlement shall perform the services pertaining to the PJM Interchange Energy Market specified in this Agreement, including, but not limited to, the following:

(i) PJMSettlement shall be the Counterparty to transactions (including ancillary services transactions and Coordinated External Transactions) in the PJM Interchange Energy Market administered by the Office of the Interconnection;

(ii) PJMSettlement shall render bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants; and

(iii) For purposes of clarity, PJMSettlement shall not be a Counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market

Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or

otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement, and as may be further described in the PJM Manuals, for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to

the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) **Bilateral Transactions.**

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.
- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and

shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller

transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

- (a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.
- (b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy

Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change

output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating

Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

- (b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.
- (c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.
- (d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.
- (e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

- (a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its Markets Gateway tools.
- (b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any

further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new Markets Gateway reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported Markets Gateway schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, in quantities sufficient

to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable, and as may be further described in the PJM Manuals.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not

desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process.

1.8.1 PJM Dispute Resolution Agreement.

Subject to the condition specified below, any Member adversely affected by a decision of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market, including the qualification of an entity to participate in that market as a buyer or seller, may seek such relief as may be appropriate under the PJM Dispute Resolution Procedures on the grounds that such decision does not have an adequate basis in fact or does not conform to the requirements of this Agreement.

1.8.2 Market or Control Area Hourly Operational Disputes.

(a) Market Participants shall comply with all determinations of the Office of the Interconnection on the selection, scheduling or dispatch of resources in the PJM Interchange Energy Market, or to meet the operational requirements of the PJM Region. Complaints arising from or relating to such determinations shall be brought to the attention of the Office of the Interconnection not later than the end of the fifth business day after the end of the Operating Day to which the selection or scheduling relates, or in which the scheduling or dispatch took place, and shall include, if practicable, a proposed resolution of the complaint. Upon receiving notification of the dispute, the Office of the Interconnection and the Market Participant raising the dispute shall exert their best efforts to obtain and retain all data and other information relating to the matter in dispute, and to notify other Market Participants that are likely to be affected by the proposed resolution. Subject to confidentiality or other non-disclosure requirements, representatives of the Office of the Interconnection, the Market Participant raising the dispute, and other interested Market Participants, shall meet within three business days of the foregoing notification, or at such other or further times as the Office of the Interconnection and the Market Participants may agree, to review the relevant facts, and to seek agreement on a resolution of the dispute.

(b) If the Office of the Interconnection determines that the matter in dispute discloses a defect in operating policies, practices or procedures subject to the discretion of the Office of the Interconnection, the Office of the Interconnection shall implement such changes as it deems appropriate and shall so notify the Members Committee. Alternatively, the Office of the Interconnection may notify the Members Committee of a proposed change and solicit the comments or other input of the Members.

(c) If either the Office of the Interconnection, the Market Participant raising the dispute, or another affected Market Participant believes that the matter in dispute has not been adequately resolved, or discloses a need for changes in standards or policies established in or pursuant to the Operating Agreement, any of the foregoing parties may make a written request for review of the matter by the Members Committee, and shall include with the request the forwarding party's recommendation and such data or information (subject to confidentiality or other non-disclosure requirements) as would enable the Members Committee to assess the matter and the recommendation. The Members Committee shall take such action on the recommendation as it shall deem appropriate.

(d) Subject to the right of a Market Participant to obtain correction of accounting or billing errors, the LLC or a Market Participant shall not be entitled to actual, compensatory, consequential or punitive damages, opportunity costs, or other form of reimbursement from the LLC or any other Market Participant for any loss, liability or claim, including any claim for lost profits, incurred as a result of a mistake, error or other fault by the Office of the Interconnection in the selection, scheduling or dispatch of resources.

1.9 Prescheduling.

The following procedures and principles shall govern the prescheduling activities necessary to plan for the reliable operation of the PJM Region and for the efficient operation of the PJM Interchange Energy Market.

1.9.1 Outage Scheduling.

The Office of the Interconnection shall be responsible for coordinating and approving requests for outages of generation and transmission facilities as necessary for the reliable operation of the PJM Region, in accordance with the PJM Manuals. The Office of the Interconnection shall maintain records of outages and outage requests of these facilities.

1.9.2 Planned Outages.

(a) A Generator Planned Outage shall be included in Generator Planned Outage schedules established prior to the scheduled start date for the outage, in accordance with standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall conduct Generator Planned Outage scheduling for Generation Capacity Resources in accordance with the Reliability Assurance Agreement and the PJM Manuals and in consultation with the Market Sellers owning or controlling the output of such resources. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from all or part of a generation resource undergoing an approved Generator Planned Outage. If the Office of the Interconnection determines that approval of a Generator Planned Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval or withdraw a prior approval. Approval of a Generator Planned Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. The Market Seller shall provide the Office of the Interconnection with an estimate of the amount of time it needs to return to service any Generation Capacity Resource on Generator Planned Outage that is already underway. If the Office of the Interconnection withholds or withdraws its approval of a Generator Planned Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Planned Outage at the earliest practical time. The Office of the Interconnection shall if possible propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Planned Outage.

(c) The Office of the Interconnection shall conduct Transmission Planned Outage scheduling in accordance with procedures specified in the Consolidated Transmission Owners Agreement and the PJM Manuals, and in accordance with the following procedures:

- (i) Transmission Owners shall use reasonable efforts to submit Transmission Planned Outage schedules one year in advance but by no later than the first of the month six months in advance of the requested start date for all outages that are expected

to exceed five working days duration, with regular (at least monthly) updates as new information becomes available.

- (ii) If notice of a Transmission Planned Outage is not provided in accordance with the requirements in subsection (i) above, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.
- (iii) Transmission Owners shall submit notice of all Transmission Planned Outages to the Office of the Interconnection by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.
- (iv) If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection shall perform this analysis and notify the Transmission Owner in a timely manner if it will require rescheduling of the outage. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the

Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

- (v) The Office of the Interconnection reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure reliable system operations on a case by case basis regardless of duration or date of submission.
- (vi) The Office of the Interconnection shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the Transmission Owner; provided, however, that the Office of the Interconnection shall not post on OASIS notice of any component of a Transmission Planned Outage to the extent such component shall directly reveal a generator outage. In such cases, the Transmission Owner, in addition to providing notice to the Office of the Interconnection as required above, concurrently shall inform the affected Generation Owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the Generation Owner on matters of safety to persons, facilities, and equipment. The Transmission Owner shall not notify any other Market Participant of such outage and shall arrange any other necessary coordination through the Office of the Interconnection.

In addition, if the Office of the Interconnection determines that transmission maintenance schedules proposed by one or more Members would significantly affect the efficient and reliable operation of the PJM Region, the Office of the Interconnection may establish alternative schedules, but such alternative shall minimize the economic impact on the Member or Members whose maintenance schedules the Office of the Interconnection proposes to modify.

- (d) The Office of the Interconnection shall coordinate resolution of outage or other planning conflicts that may give rise to unreliable system conditions. The Members shall comply with all maintenance schedules established by the Office of the Interconnection.

1.9.3 Generator Maintenance Outages.

- (a) A Generator Maintenance Outage may only be scheduled if approved by the Office of the Interconnection prior to the requested start date for the outage, in accordance with subsection (b) hereof and the standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall schedule Generator Maintenance Outages for Generation Capacity Resources in accordance with the procedures specified in the PJM Manuals and in consultation with the Market Seller owning or controlling the output of such resources. The Office of the Interconnection shall approve requests for Generator Maintenance Outages for such a Generation Capacity Resource unless the outage would threaten the adequacy of reserves in, or the reliability of, the PJM Region. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from a generation resource undergoing an approved full or partial Generator Maintenance Outage. If the Office of the Interconnection determines that approval of a Generator Maintenance Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval, withdraw a prior approval, or rescind a prior approval of a Generator Maintenance Outage that is already underway. Approval of a Generator Maintenance Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. In addition, if the Office of the Interconnection determines that it must rescind its approval of a Generator Maintenance Outage that is already underway in order to preserve the reliable operation of the PJM Region, the Office of the Interconnection will provide the Market Seller of the Generation Capacity Resource at least 72 hours' notice thereof. The Market Seller shall be required to make the Generation Capacity Resource available for normal operation within 72 hours of such notice. If the generator is not made available for normal operation by 72 hours after the notice of the rescission of the approval of the Generator Maintenance Outage, for the remaining time the resource continues on the outage it shall be deemed to have experienced a Generator Forced Outage. If the Office of the Interconnection withholds, withdraws or rescinds approval of a Generator Maintenance Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Maintenance Outage at the earliest practical time. The Office of the Interconnection shall, if possible, propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Maintenance Outage.

1.9.4 Forced Outages.

(a) Each Market Seller that owns or controls a pool-scheduled resource, or Generation Capacity Resource whether or not pool-scheduled, shall: (i) advise the Office of the Interconnection of a Generator Forced Outage suffered or anticipated to be suffered by any such resource as promptly as possible; (ii) provide the Office of the Interconnection with the expected date and time that the resource will be made available; and (iii) make a record of the events and circumstances giving rise to the Generator Forced Outage. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or satisfy delivery obligations, from a generation resource undergoing a Generator Forced Outage. A Generation Capacity Resource committed to PJM loads through an RPM Auction, FRR Capacity Plan, or by designation as a replacement resource under Attachment DD of the PJM Tariff, that does not deliver all or part of its scheduled energy shall be deemed to have experienced a Generator Forced Outage with respect to such undelivered energy, in accordance with standards and procedures for full and partial Generator Forced Outages specified in the Reliability Assurance Agreement, and the PJM Manuals.

(b) The Office of the Interconnection shall receive notification of Forced Transmission Outages, and information on the return to service, of Transmission Facilities in the PJM Region in accordance with standards and procedures specified in, as applicable, the Consolidated Transmission Owners Agreement and the PJM Manuals.

1.9.4A Transmission Outage Acceleration.

(a) Planned Transmission Outages and Forced Transmission Outages otherwise scheduled pursuant to sections 1.9.2 and 1.9.4 respectively of this Schedule may be accelerated or rescheduled at the request of a Generation Owner or other Market Participant in accordance with the terms and conditions of this section 1.9.4A and the PJM Manuals.

(b) Transmission Outages Requiring Coordination With A Specific Generation Owner.

- (i) Receipt of Acceleration Request. Prior to a scheduled Planned Transmission Outage associated with the interconnection of a generating unit to the Transmission System, the affected Generation Owner may request that the outage be accelerated or rescheduled. Such Acceleration Request shall be submitted to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals.
- (ii) Determination to Accommodate Acceleration Request. Upon receipt of an Acceleration Request, the Office of the Interconnection shall notify the affected Transmission Owner of such Acceleration Request. The affected Transmission Owner shall determine, in its sole discretion, whether to accelerate or reschedule a transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards, and shall consider any requirements contained in pertinent collective bargaining agreements. In the event that the affected Transmission Owner determines to accelerate or reschedule a transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an estimate of the cost to accelerate or reschedule the transmission outage and the revised schedule for the transmission outage ("Acceleration Estimate").
- (iii) Provision of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that the Generation Owner has met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Generation Owner with the Acceleration Estimate. In the event that the Generation Owner does not meet the creditworthiness standard, the Office of the Interconnection shall not provide the Acceleration Estimate and the transmission outage shall not be accelerated or rescheduled. Upon receipt of the Acceleration Estimate, the Generation Owner, within the time period specified in the PJM Manuals, shall notify the Office of the

Interconnection as to whether it desires to accelerate or reschedule the transmission outage pursuant to the terms of the Acceleration Estimate.

- (iv) **Cost Responsibility.** In the event the Generation Owner notifies the Office of the Interconnection that it desires to proceed with the acceleration or rescheduling of the transmission outage pursuant to section 1.9.4A(a)(iii), the Generation Owner shall be solely responsible for actual costs incurred by the affected Transmission Owner for the acceleration or rescheduling of the transmission outage. The Generation Owner's cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete the outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the Generation Owner. After receipt of such notification, within the time period set forth in the PJM Manuals, the Generation Owner shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection shall notify the affected Transmission Owner of the Generation Owner's decision. In the event the Generation Owner desires not to proceed, the transmission outage shall occur according to normal work practices and the Generation Owner shall be responsible for all incurred costs and committed costs and obligations of the affected Transmission Owner for the acceleration or rescheduling of the transmission outage as of the date that the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(c) **Transmission Outages That Could Cause Congestion Revenue Inadequacy.**

- (i) **Posting of Transmission Outage.** In the event that the Office of the Interconnection determines that a Planned Transmission Outage or Forced Transmission Outage could exceed five days and could cause congestion revenue inadequacy in excess of \$500,000, the Office of the Interconnection shall post a notice of such transmission outage on its internet site. Within the time period and pursuant to the procedures set forth in the PJM Manuals, any Market Participant may request that such transmission outage be accelerated or rescheduled.
- (ii) **Determination to Accelerate or Reschedule Transmission Outage.** Upon receipt of the Acceleration Request(s) pursuant to section 1.9.4A(b)(i), the Office of the Interconnection shall notify the affected Transmission Owner of such request(s). The affected Transmission Owner shall determine in its sole discretion whether to accelerate or reschedule the transmission

outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards and shall consider any requirements contained in pertinent collective bargaining agreements. If the affected Transmission Owner determines to accelerate or reschedule the transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an Acceleration Estimate. In the event that Market Participants submit requests which would require different schedules for a transmission outage, the Office of the Interconnection, in consultation with the affected Transmission Owner, shall determine the most effective option, which will be included in the Acceleration Estimate.

- (iii) Notification of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that Market Participants requesting acceleration or rescheduling of transmission outages have met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Market Participants with the Acceleration Estimate and the number of Market Participants requesting acceleration or rescheduling of the transmission outage that meet the creditworthiness standards. After receipt of the Acceleration Request, within the time period set forth in the PJM Manuals, each requesting Market Participant meeting the creditworthiness standards shall notify the Office of the Interconnection whether it desires to accelerate or reschedule the transmission outage as set forth in the Acceleration Estimate, and if it desires to accelerate or reschedule the transmission outage, the amount it is willing to pay for such acceleration or rescheduling.
- (iv) Evaluation of Acceleration Requests. Upon receipt of Market Participant(s) notifications pursuant to subsection 1.9.4A(b)(iii), the Office of the Interconnection shall determine, based on the amount Market Participants collectively are willing to pay for accelerating or rescheduling of the transmission outage, whether the transmission outage should be accelerated or rescheduled. The transmission outage shall be accelerated or rescheduled if the amount that the Market Participants collectively are willing to pay for accelerating or rescheduling a transmission outage exceeds the Acceleration Estimate by the following margins: (a) for outages to equipment outside a substation, two times the Acceleration Estimate; and (b) for outages to equipment inside a substation, five times the Acceleration Estimate. These margins are designed to provide a reasonable degree of certainty that the actual costs of accelerating or rescheduling the transmission outage will not exceed the amount the Market Participants are willing to pay. In all events, transmission outages will be accelerated or rescheduled pursuant to requests made under section 1.9.4A(c) only when the requested acceleration or rescheduling would

reduce the amount of congestion revenue inadequacy resulting from the outage as determined by the Office of the Interconnection.

- (v) **Cost Responsibility.** Each Market Participant which notifies the Office of the Interconnection pursuant to section 1.9.4A(b)(iii) that it is willing to pay for the acceleration or rescheduling of a transmission outage shall be responsible for the actual costs of such acceleration or rescheduling on a pro-rata basis based on the amount it specified it was willing to pay for the acceleration or rescheduling. Market Participants' cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete a transmission outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the affected Market Participants of such increase. Within the time period set forth in the PJM Manuals, each affected Market Participant shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection then shall notify the affected Transmission Owner of each affected Market Participant's decision. In the event that, because one or more Market Participants determine not to proceed, there would be insufficient funds to pay for the full cost of accelerating or rescheduling a transmission outage, the transmission outage shall not continue to be accelerated or rescheduled and shall occur according to normal work practices. In such instance, the Market Participants shall be responsible on a pro-rata basis for all incurred costs and committed costs and obligations of the affected Transmission Owner as of the date the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

- (d) **Posting Revised Transmission Outages.** The Office of the Interconnection shall post on its internet site all revised transmission outage schedules resulting from implementation of this section 1.9.4A, pursuant to the procedures in the PJM Manuals, and simultaneously shall notify affected Market Participants or Generation Owners that submitted Acceleration Requests of the Transmission Owner's agreement to accelerate or reschedule the outage.

1.9.5 Market Participant Responsibilities.

Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered.

1.9.6 Internal Market Buyer Responsibilities.

Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based start-up and no-load fees may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit both start-up and no-load fees on either a market basis or a cost basis and any such election shall be submitted on or before March 31 for the period of April 1 through September 30, and on or before September 30 for the period October 1 through March 31. The election of market-based or cost-based start-up and no-load fees shall remain in effect without change throughout the applicable periods.

- (i) If a Market Seller chooses to submit market-based start-up and no-load fees, such Market Seller, in its Offer Data, shall submit the level of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends to request such fees. The Office of the Interconnection shall reject any request for start-up and no-load fees in a Market Seller's Offer Data that does not conform to the Market Seller's specification on file with the Office of the Interconnection.
- (ii) If a Market Seller chooses to submit cost-based start-up and no-load fees, such fees must be calculated as specified in the PJM Manuals and the Market Seller may change both cost-based fees daily and must change both fees as the associated costs change, but no more frequently than daily.

1.9.8 Transmission Owner Responsibilities.

All Transmission Owners shall regularly update and verify facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals:

- (a) Each Transmission Owner shall verify to the Operations Planning Department (or successor Department) of the Office of the Interconnection all of its transmission facility ratings two months prior to the beginning of the summer season (i.e., on April 1) and two months prior to the beginning of the winter season (i.e., on October 1) each calendar year, and shall provide detailed data justifying such transmission facility ratings when directed by the Office of the Interconnection.
- (b) In addition to the seasonal verification of all ratings, each Transmission Owner shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection updates to its transmission facility ratings as soon as such Transmission Owner is aware of any changes. Such Transmission Owner shall provide the Office of the Interconnection with detailed data justifying all such transmission facility ratings changes.
- (c) All Transmission Owners shall submit to the Operations Planning Department (or successor Department) of the Office of the Interconnection formal documentation of any procedure for changing facility ratings under specific conditions, including: the detailed conditions under which such procedures will apply, detailed explanations of such procedures, and detailed calculations justifying such pre-established changes to facility ratings. Such procedures must be updated twice each year consistent with the provisions of this Section.

1.9.9 Office of the Interconnection Responsibilities.

- (a) The Office of the Interconnection shall perform seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system, in accordance with the procedures specified in the PJM Manuals.
- (b) The Office of the Interconnection shall maintain and update tables setting forth Operating Reserve and other reserve objectives as specified in the PJM Manuals and as consistent with the Reliability Assurance Agreement.
- (c) The Office of the Interconnection shall receive and process requests for firm and non-firm transmission service in accordance with procedures specified in the PJM Tariff.
- (d) The Office of the Interconnection shall maintain such data and information relating to generation and transmission facilities in the PJM Region as may be necessary or appropriate to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM Region.
- (e) The Office of the Interconnection shall maintain an historical database of all transmission facility ratings, and shall review, and may modify or reject, any submitted change or any submitted procedure for pre-established transmission facility rating changes. Any dispute between a Transmission Owner and the Office of the Interconnection concerning transmission facility ratings shall be resolved in accordance with the dispute resolution procedures in schedule 5 to the Operating Agreement; provided, however, that the rating level determined by the Office of the Interconnection shall govern and be effective during the pendency of any such dispute.

(f) The Office of the Interconnection shall coordinate with other interconnected Control Area as necessary to manage, alleviate or end an Emergency.

1.10 Scheduling.

1.10.1 General.

- (a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.
- (b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.
- (c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than *10:30 a.m.* on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:

- (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and
- (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified

in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not dynamically scheduled to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an “Up-to Congestion Transaction.” Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited to those paths posted on the PJM internet site and determined by the Office of the Interconnection using the following criteria:

Step 1: Start with the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.

Step 2: Remove from the list of nodes described in Step 1 all load buses below 69 kV.

Step 3: Remove from the resulting set of nodes from Step 2 all generator buses at which no generators of 100 megawatts or more are connected.

Step 4: Remove from the results of Step 3 all electrically equivalent nodes.

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day *for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly.* Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage are subject to a Day-ahead Energy Market must-offer requirement and a Real-time Energy Market must-offer requirement and pursuant thereto shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the Day-ahead Energy Market must-offer requirement and the Real-time Energy Market must-offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each *clock* hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;
- ii) Shall specify the amounts and prices for *each clock hour during* the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with *additional* schedules applicable if accepted after the foregoing deadline;

- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer *for the clock hour*, which offer shall remain open through the Operating Day, for which the offer is submitted, *unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals*;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, *unless modified after the close of the Day-ahead Energy Market as permitted pursuant to section 1.10.9B of this Schedule*;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, *except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour*;
- ix) Shall not exceed an energy offer price of \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00, for all Economic Load Response Resources;
- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:
 - a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;
 - b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and
 - c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, \$1,100/megawatt-hour.

- xi) May be updated hourly, up to 60 minutes before the applicable clock hour during the Operating Day.*

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation *for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation* that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. *Such offers may vary hourly, and may be updated each hour, up to 60 minutes before the applicable clock hour during the Operating Day.* The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such

resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

- (g) Each *component of an* offer by a Market Seller of a Generation Capacity Resource *that is constant for the entire Operating Day and does not vary hour to hour* shall remain in effect for subsequent Operating Days until superseded or canceled.
- (h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.
- (i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.
- (j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve *for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve* that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. *Such offers may vary hourly, and may be updated each hour up to 60 minutes before the applicable clock hour during the Operating Day.* The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.
- (k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection *for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand.* The offer must equal or exceed 0.1 megawatts, *may vary hourly*, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational

Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. *Such offers may be updated each hour, up to 60 minutes before the applicable clock hour during the Operating Day.* Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) *per hour*.

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The *megawatt* quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the

resource is expected to be needed to maintain system reliability during the Operating Day, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the

basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

- (i) enter its election on OASIS by *10:30 a.m.* of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and
 - (ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.
- (b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.
- (c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

- (a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv)

the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) *By 1:30 p.m., or as soon as practicable thereafter*, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in Section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection

(b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from *the time the Office of the Interconnection posts the*

results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows *and as specified in section 1.10.9B of this Schedule:*

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) *The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the*

Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9B Updating Offers in Real-time

Each Market Seller may submit Real-time Offers for a resource up to 60 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

- (a) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller shall not submit a market-based Real-time Offer in that is higher than its market-based offer in effect at the time of commitment.*
- (b) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved fuel cost policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.*
- (c) If a Market Seller's available cost-based offer is not compliant with Schedule 2 of the Operating Agreement and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, and the current price of the available cost-based offer for that clock hour exceeds the Market Seller's estimation of its new cost-based offer for the hour by more than \$5/MWh, the Market Seller must submit an updated cost-based Real-time Offer for that clock hour that is compliant with Schedule 2 of the Operating Agreement and the PJM Manuals.*

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001. PJMSettlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement

shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled generation resources as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources eligible to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources not providing energy because they are providing Non-Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

1.12 Dynamic Transfers.

- (a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Operating Reserve Credit shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.
- (b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Operating Reserve Credit shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.
- (c) The Transmission Provider shall implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.
- (d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Transfer to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.
- (e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

1.13 Coordinated Transaction Scheduling

- (a) The provisions of this Section 1.13 apply to Coordinated External Transactions.
- (b) A CTS Interface Bid submitted in the Real-time Energy Market shall specify the sink, the corresponding source, and a duration consisting of one or more consecutive quarter-hour increments. A CTS Interface Bid shall include a bid price and a bid quantity for each quarter-hour increment. A CTS Interface Bid may not be submitted or modified later than 75 minutes before the start of the hour that includes the first quarter-hour increment for which the CTS Interface Bid is offered. A CTS Interface Bid must include the associated NERC E-Tag at the time it is submitted.
- (c) CTS Interface Bids are cleared in economic merit order for each quarter-hour increment, based upon the forecasted price differential across the CTS Enabled Interface. Subject to Transmission System conditions and operating limits as described in this subsection (c) below, and credit limits and requirements as described in Attachment Q of the PJM Tariff, a CTS Interface Bid will clear if the forecasted price differential across the CTS Enabled Interface is greater than or equal to the bid price. The total quantity of CTS Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the CTS Interface Bids of all Market Participants, Transmission System conditions, and any real-time operating limits necessary to ensure reliable operation of the Transmission System.
- (d) Any Coordinated External Transaction, or portion thereof, submitted to the Real-time Energy Market will not be scheduled if PJM expects that the transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

2. CALCULATION OF LOCATIONAL MARGINAL PRICES

2.1 Introduction.

The Office of the Interconnection shall calculate the price of energy at the load buses and generation buses in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region on the basis of Locational Marginal Prices. Locational Marginal Prices determined in accordance with this Section shall be calculated on a day-ahead basis for each hour of the Day-ahead Energy Market, and every five minutes during the Operating Day for the Real-time Energy Market.

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained economic dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load buses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers, except that generation resources will be dispatched in economic merit order but limited to \$2,000/megawatt-hour for purposes of calculating Locational Marginal Prices. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-ahead or Real-time Energy Markets or from Emergency Load Response and Pre-Emergency Load Response participants in the Real-time Energy Market.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

(d) The Office of the Interconnection shall use its security-constrained economic dispatch software program to monitor system conditions to avoid transient conditions that incorrectly imply that a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage (“false positives”) by: (i) forecasting system conditions for up to several hours into the future and producing an interim security-constrained economic dispatch solution, and (ii) forecasting system conditions on a shorter term basis and producing a real-time security-constrained economic dispatch solution. If the security-constrained economic dispatch software program forecasts a Primary Reserve shortage and/or a Synchronized Reserve shortage in both the interim and real-time security-constrained economic dispatch solutions, as may be further described in the PJM Manuals, the Office of the Interconnection shall deem this to be a Primary Reserve shortage and/or a Synchronized Reserve shortage and shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Real-Time Locational Marginal Price program. Shortage pricing shall exist until both the interim and real-time security-constrained economic dispatch solutions are able to meet the specified reserve requirements and no Voltage Reduction Action or Manual Load Dump Action is still in effect. If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem with or malfunction of the security-constrained economic dispatch software program, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(e) The Office of the Interconnection shall submit to the Commission, for informational purposes, a status report within sixty (60) days of the occurrence of a false positive or actual Primary Reserve shortage and/or a Synchronized Reserve shortage.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

- (a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.
- (b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine the applicable marginal energy offer of the resources being dispatched by the Office of the Interconnection. A resource shall be included in the calculation of Real-time Prices if the applicable marginal energy offer of the resource being dispatched by the Office of the Interconnection is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located, provided that offers for resources dispatched by the Office of the Interconnection in excess of \$2,000/megawatt-hour will be capped at \$2,000/megawatt-hour for purposes of calculating Real-time Prices.
- (c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the applicable marginal energy offer by comparing the requested megawatt output of the resource with the Market Seller's offer price curve. The applicable marginal energy offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate nor \$2,000/megawatt-hour. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM security-constrained economic dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(b) If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated as described below.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all

affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was forecasted in both security-constrained economic dispatch solutions as described in Section 2.2(d) above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable. The

Reserve Penalty Factor for the Primary Reserve Requirement and the Reserve Penalty Factor for the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable, until the Manual Load Dump Action has been terminated.

Shortage pricing will be terminated in a Reserve Zone or Reserve Sub-Zone when demand and reserve requirements can be fully satisfied with generation and demand response resources and any Voltage Reduction Action and/or Manual Load Dump Action taken for that Reserve Zone or Reserve Sub-Zone has also been terminated.

(e) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

2.6 Calculation of Day-ahead Prices.

For the Day-ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications (including PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads that they serve), offers for generation, dispatchable load, Increment Offers, Decrement Bids, offers for demand reductions, and bilateral transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.

2.6A Interface Prices.

PJM shall from time to time, as appropriate, define and revise Interface Pricing Points for purposes of calculating LMPs for energy exports to or energy imports from external balancing authority areas. Such Interface Pricing Points may represent external balancing authority areas, aggregates of external balancing authority areas, or portions of any external balancing authority area. Subject to the terms of this Section 2.6A, PJM may define Interface Pricing Points and interface pricing methods for a sub-area of a balancing authority area different from the pricing points and interface pricing methods applicable to the adjacent balancing authority area where the sub-area is located, and no action of the balancing authority area or any entity whose transactions do not source and/or sink within the sub-area shall affect the pricing points or interface pricing methods established for such sub-area. Definitions of Interface Pricing Points and price calculation methodologies may vary, depending on such factors as whether an external balancing authority area operates an organized electric market with locational pricing, whether the external balancing authority has entered an interregional congestion management agreement with PJM, and the availability of data from the external balancing authority area on such relevant items as unit costs, run status, and output. PJM shall negotiate in good faith with any external balancing authority that seeks to enter into an interregional congestion management agreement with PJM, and will file such agreement, upon execution, with the Commission. In the event PJM and an external balancing authority do not reach a mutually acceptable agreement, the external balancing authority may request, and PJM shall file with the Commission within 90 days after such request, an unexecuted congestion management agreement for such balancing authority. Nothing herein precludes PJM from entering into agreements with External Resource owners for the Dynamic Transfer of such resources, as contemplated by section 1.12 of this Schedule, at prices determined in accordance with such agreements. Acceptable pricing point definitions and pricing methodologies include, but are not limited to, the following:

- (a) **External Balancing Authority Areas that are Part of Larger Centrally Dispatched Organizations.** PJM shall determine a set of nodes external to the PJM system representing an external balancing authority area or set of balancing authority areas via flow analysis, utilizing standard power flow analysis tools, of the impact of transactions from the balancing authority area or areas on the transmission facilities connecting PJM with such external area(s). PJM shall then weight the contribution of each identified node to the calculation of the interface price. For each Interface Pricing Point, a set of tie lines will be defined and each node in the interface definition will be assigned to a tie line. PJM shall utilize the sensitivity of the tie lines to an injection at each external pricing point to weight the node associated with that tie line in the Interface Pricing Point calculation, as more fully described in the PJM Manuals.
- (b) **External Areas that are Not Part of Larger Centrally Dispatched Organizations.** PJM may define pricing points aggregating multiple directly or non-directly connected external balancing authority areas that are not part of larger centrally dispatched organizations. Prices at such points representing aggregated balancing authority areas shall be determined as described in subsection (a) above; provided, however, that PJM shall define Interface Pricing Points corresponding to individual, directly connected balancing authority areas, and establish alternative pricing methodologies for use as to such areas, to the extent that necessary supporting data is provided from the external area, as follows:

(1) PJM will define an Interface Pricing Point corresponding to a directly connected individual external balancing authority area or sub-area within a directly connected balancing authority area and determine prices in accordance with High-Low Pricing, as defined in section (A) below, if the balancing authority area or sub-area within the balancing authority area provides the data described in section (B) below.

(A) Under High-Low Pricing, the price for imports of energy to PJM from the external balancing authority area shall equal the LMP calculated by PJM at the generator bus in such area with an output greater than 0 MW that has the lowest price in such area; and the price for exports of energy from PJM to the external balancing authority area shall equal the price at the generator bus in such area with an output greater than 0 MW that has the highest price in such area, updated every 5 minutes and aggregated on an hourly basis in the real time market and calculated for each hour in the Day-Ahead market, to the extent and for the periods that the information described below is provided.

(B) Such pricing point and pricing methodology shall be provided only to the extent the external balancing authority area or sub-area provides or causes to be provided to PJM real-time telemetered load, generation and similar data for such area or sub-area demonstrating that the transaction receiving such pricing sources, or sinks as appropriate, in such area or sub-area. Such data shall be of the type and in the form specified in the PJM Manuals. If such data is provided, any transaction, regardless of participant, sourcing or sinking in such area will be priced in accordance with section (A) above. During any hour in which any entity makes any purchases from other external areas outside of such area or sub-area (other than delivery of external designated Network Resources or such other exceptions specifically documented for such area or sub-area in the PJM Manuals) at the same time that energy sales into PJM are being made, or purchases energy from PJM for delivery into such area or sub-area while sales from such area to other external areas are simultaneously implemented (subject to any exceptions specifically documented for such area or sub-area in the PJM Manuals), pricing will revert to the applicable import or export pricing point that would otherwise be assigned to such external area or sub-area.

(2) PJM will define an Interface Pricing Point corresponding to an individual external balancing authority area or sub-area within a directly connected balancing authority area and determine prices in accordance with Marginal Cost Proxy Pricing, as defined in section (A) below, if the balancing authority area or sub-area within a directly connected balancing authority area provides, in addition to the data specified in section (1)(B) above, the data described in section (B) below, provided, however, that such pricing methodology shall terminate, and pricing shall be governed by the methodology described in subsection (a) or (b)(1) above, as applicable, on January 31, 2010 for any external balancing authority area that has not executed an interregional congestion management agreement with the Office of the Interconnection prior to January 31, 2010.

(A) Under Marginal Cost Proxy Pricing, PJM shall compare the individual bus LMP for each generator in the PJM model in the directly connected balancing authority area or sub-area having a telemetered output greater than zero MW to the marginal cost for that generator.

In real time, during each 5-minute calculation of LMPs for the PJM Region, PJM shall calculate the energy price for imports to PJM from such area or sub-area as the lowest LMP of any generator bus in such area or sub-area with an output greater than 0 MW that has an LMP less than its marginal cost for such 5-minute interval. If no generator with an output greater than 0 MW has an LMP less than its marginal cost, then the import price shall be the average of the bus LMPs for the set of generators in such area with an output greater than 0 MW that PJM determines to be the marginal units in that area for that 5-minute interval. PJM shall determine the set of marginal units in the external area by summing the output of the units serving load in that area in ascending order of the units' marginal costs until such sum equals the real time load in such external area. Units in the external area with marginal costs at or above that of the last unit included in the sum shall be the marginal units for that area for that interval.

PJM similarly shall calculate the energy price for exports from PJM to such area or sub-area as the highest LMP of any generator bus in such area or sub-area with an output greater than 0 MW that has an LMP greater than its marginal cost for such 5-minute interval. If no generator with an output greater than 0 MW has an LMP greater than its marginal cost, then the export price shall be the average of the bus LMPs for the set of generators with an output greater than 0 MW that PJM determines to be the marginal units in such area for that 5-minute interval, as described above. The hourly integrated import and export prices will be the average of all 5-minute interval prices during such hour.

Locational interface prices in the Day-ahead Market shall be calculated in the same manner as set forth above for the Real-time Market, utilizing information regarding whether each unit in such area is scheduled to run for each hour of the following day, provided as specified in subsection (B) below.

(B) Such pricing point and pricing methodology shall be provided only to the extent the external balancing authority area or sub-area provides or causes to be provided to PJM (i) unit-specific, real time telemetered output data for each unit in the PJM network model in such area or sub-area; (ii) unit-specific marginal cost data for each unit in the PJM network model in such area or sub-area, prepared in accordance with the PJM Manuals and subject to the same review of the PJM Independent Market Monitor as any such cost data for internal PJM units; and (iii) a day-ahead indication for each unit in such area or sub-area as to whether that unit is scheduled to run for each hour of the following day. During any hour in which any entity makes any purchases from other external areas outside of such area or sub-area (other than delivery of external designated Network Resources or such other exceptions specifically documented for such

area or sub-area in the PJM Manuals) at the same time that energy sales into PJM are being made, or purchases energy from PJM for delivery into such area or sub-area while sales from such area to other external areas are simultaneously implemented (subject to any exceptions specifically documented for such area or sub-area in the PJM Manuals), pricing will revert to the applicable import or export pricing point that would otherwise be assigned to such external area or sub-area.

(C) PJM shall post the individual generator bus LMPs in the directly connected external control areas for informational purposes; provided, however, that no settlement shall take place at such external bus LMPs, and such nodes shall not be available for the submission of Virtual Transactions in the PJM Day-ahead Energy Market.

(3) All data provided to PJM by balancing and/or reliability authorities hereunder will be used only for the purpose of implementing the interface pricing set forth herein, will be treated confidentially by PJM, and will be afforded the same treatment provided to Member confidential data under the PJM Operating Agreement.

(4) PJM reserves the right to audit the data supplied to PJM hereunder by giving written notice to the relevant balancing/reliability authority/market operator no more than three months following provision of such data, and at least ten (10) business days in advance of the date that PJM wishes to initiate such audit, with completion of the audit occurring within sixty (60) days of such notice. Each party shall be responsible for its own expenses related to any such audit.

2.7 Performance Evaluation.

The Office of the Interconnection shall undertake an evaluation of the foregoing procedures for the determination of Locational Marginal Prices, as well as the procedures for determining and allocating Financial Transmission Rights and associated Transmission Congestion Charges and Credits, not less often than every two years, in accordance with the PJM Manuals. To the extent practical, the Office of the Interconnection shall retain all data needed to perform comparisons and other analyses of locational marginal pricing. The Office of the Interconnection shall report the results of its evaluation to the Market Participants, along with its recommendations, if any, for changes in the procedures. The Office of the Interconnection shall prepare reports, with regard to participation of Economic Load Response Participants in the PJM Interchange Energy Market, as required by the FERC and the PJM Manuals.

3. ACCOUNTING AND BILLING

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

- (a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.
- (b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.
- (e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.
- (f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output in the preceding shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal, Response}(\delta, \delta+5 \text{ Min}); \delta=0 \text{ to } 5 \text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \text{max} ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

- (i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).
- (ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.
- (iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the *applicable offer* for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price *for start-up (shutdown costs for Demand Resources) and no-load fees and energy* summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to

operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits,

identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

- (iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a

segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's *Total Operating Reserve Offer*, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (*excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer*), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted

against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) *the Total Lost Opportunity Offer*, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's *Generation Resource* Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.
- (ii) for each hour a unit is scheduled to produce energy in the Day-ahead Energy Market, but the unit is not called on by the Office of the Interconnection and does not operate in real time, then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the *Total Lost Opportunity Offer* plus no-load costs, plus (D) the start-up cost, divided by the hours committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during

any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market; or

- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the *Total Lost Opportunity Offer*, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the

Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh *and greater than the Market Seller's lowest available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price *for a market-based offer* is greater than \$1,000/MWh *and greater than the Market Seller's lowest available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to \$1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered

during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed \$1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp_Request}_t = \frac{(\text{UDS_target}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLA_time}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

where:

1. UDS_target = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time

4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is ≤ 10 , or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

- (i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing

Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating

Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) *Market Sellers that incur incremental operating costs for a generation resource greater than \$2,000/MWh, determined in accordance with Schedule 2 of the Operating Agreement and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).*

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

- i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.
- ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined

by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

- iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending

October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation

for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with subsection (c) below, plus the amounts, if any, described in subsection (f) below.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the

contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

- (i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.
- (ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.
- (iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer

dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

- (iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

- (i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying

to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

- (ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or

self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the *Total Lost Opportunity Offer*, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's *Generation Resource* Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to $\{(AG - LMPD_{MW}) \times (UB - URTLMP)\}$ where:

AG equals the actual hourly integrated output of the unit;

LMPD_{MW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to *the lesser of the Final Offer or Committed Offer*;

URLMP equals the real time LMP at the unit's bus; and

where $UB - URLMP$ shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating

unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element (“contingency flow”) exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility (“post-contingency operation”). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit’s operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource’s hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource’s start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit’s cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its

net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

- (a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.
- (b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).
- (c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.
- (d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.5A Non-Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Non-Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, except for the months of June through September in the Delivery Year, the following formula shall be used to measure an Emergency and Pre-Emergency Load Response participant's demand reductions when determining compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
 - i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 - 1. NERC holidays;
 - 2. Weekend days;
 - 3. Event days. For the purposes of this section an event day shall be either:
 - i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a

Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.
- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.
- ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.
 - iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to

section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

- ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully

specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Real-time Energy Market no later than 2:15 p.m. on the day prior to the operating day that submitted a day-ahead offer that cleared or that otherwise are dispatched by the Office of the Interconnection in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may revise the previously specified minimum or maximum load reduction quantity for an operating hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than three hours prior to such operating hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided

however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$
and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;

RTL_{iz} is the real-time load for LSE i in zone z ;
 X is the total export quantity from PJM in that hour; and
 X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM

Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.
 - i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.
 - ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.
- v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load

calculation, interval meter owner and a known recurring End-Use
Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or buses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

PJMSettlement on behalf of PJM shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

3.6 Metering Reconciliation.

3.6.1 Meter Correction Billing.

Metering errors and corrections will be reconciled at the end of each month by a meter correction charge (positive or negative). The monthly meter correction charge for tie meter corrections shall be the product of the positive or negative deviation in energy amounts, times the load weighted average real-time Locational Marginal Price for all hours of that month for all load buses in the PJM Region. The monthly meter correction charge for generator meter corrections shall be the product of the positive or negative deviation in energy amounts, times the generation weighted average Locational Marginal Price at that generator's bus for all hours of that month.

3.6.2 Meter Corrections Between Market Participants.

If a Market Participant or the Office of the Interconnection discovers a meter error affecting an interchange of energy with another Market Participant and makes the error known to such other Market Participant prior to the completion by the Office of the Interconnection of the accounting for the interchange, and if both Market Participants are willing to adjust hourly load records to compensate for the error and such adjustment does not affect other parties, an adjustment in load records may be made by the Market Participants in order to correct for the meter error, provided corrected information is furnished to the Office of the Interconnection in accordance with the Office of the Interconnection's accounting deadlines. No such adjustment may be made if the accounting for the Operating Day in which the interchange occurred has been completed by the Office of the Interconnection. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participants experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied to the Market Participants. For Market Participants that are Electric Distributors that request the debit and credit to be further allocated to all Network Service Users in their territory (as documented in the PJM Manuals), where all Load Serving Entities in the respective Electric Distributor territory agree, the appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the applicable territory.

3.6.3 500 kV Meter Errors.

Billing shall be adjusted to account for errors in meters on 500 kV Transmission Facilities within the PJM Pre-Expansion Zones (excluding Allegheny Power) or between the PJM Pre-Expansion Zones (excluding Allegheny Power) and Allegheny Power. The Market Participant with the tie meter or generator meter experiencing the error shall account for the full amount of the discrepancy and an appropriate debit or credit shall be applied among Electric Distributors that report hourly net energy flows from metered tie lines in the Pre-Expansion Zones (excluding Allegheny Power) in proportion to the load consumed in their territories. The error shall be accounted for by a correction at the end of the billing cycle. For Market Participants that are Electric Distributors that request the debit and credit to be further allocated to all Network Service Users in their territory (as documented in the PJM Manuals), where all Load Serving Entities in the respective Electric Distributor territory agree, the appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the

applicable territory.

3.6.4 Meter Corrections Between Control Areas.

An error between accounted for and metered interchange between a Party in the PJM Region and an entity in a Control Area other than the PJM Region shall be corrected by adjusting the hourly meter readings. If this is not practical, the error shall be accounted for by a correction at the end of the billing cycle. The Market Participant with ties to such other Control Area experiencing the error shall account for the full amount of the discrepancy. However, if the meter correction applies to a tie on the 500 kV system between the PJM Pre-Expansion Zones (excluding Allegheny Power) and other Control Areas, Electric Distributors that report hourly net energy flows from metered tie lines in the Pre-Expansion Zones (excluding Allegheny Power) shall account for the full amount of the discrepancy in proportion to the load consumed in their territories. The appropriate debit or credit shall be applied among Network Service Users in proportion to their deliveries to load served in the PJM Region. The Office of the Interconnection will adjust the actual interchange between the other Control Area and the PJM Region to maintain a proper record of inadvertent energy flow.

3.6.5 Meter Correction Data.

Meter error data shall be submitted to the Office of the Interconnection not later than the last business day of the month following the end of the monthly billing cycle applicable to the meter correction.

3.6.6 Correction Limits.

A Market Participant may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter error shall be limited to bills for transactions occurring in the most recent annual accounting period of the billing Market Participant in which the meter error occurred, and the prior annual accounting period.

3.7 Inadvertent Interchange.

Inadvertent Interchange will be reconciled each hour by a charge allocation (positive or negative) applied to Network Service Users in proportion to their deliveries to load in the PJM Region, which shall be the product of the positive or negative Inadvertent Interchange amount times the PJM load weighted average Locational Marginal Price for that hour.

4. [Reserved For Future Use]

**5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION
CONGESTION AND LOSSES**

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) (i) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJMSettlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load settlements ("load contract"), including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold Provider of Last Resort ("POLR") auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the LSEs whose bids were accepted in the auction ("POLR Suppliers") based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section

1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm

Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating

Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each FTR Holder shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If an Effective FTR Holder between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An Effective FTR Holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

- (a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.
- (b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the FTR Holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the FTR Holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the FTR Holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the FTR Holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.
- (i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.
- (ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

- (iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the FTR Holder shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.
 - (iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.
 - (v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.
 - (vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.
- (e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

- (i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.
- (ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an unanticipated event outside the control of PJM that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result

of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

- (iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) Reserved.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each FTR Holder shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR Holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR Holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 “Distribution of Excess Congestion Charges.”

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each FTR Holder shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR Holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR Holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR Holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.
2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.
3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning

Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the FTR Holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the FTR Holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR Holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.
2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[total \text{ excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [total \text{ Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [total \text{ Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

5.3 Unscheduled Transmission Service (Loop Flow).

- (a) When there are agreements between the LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.
- (b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owners with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

- (a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule.
- (b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

- (a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases.
- (b) Market Buyers shall be charged for transmission losses resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant load bus.
- (c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.
- (d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.
- (e) (i) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion

to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(ii) To determine the amount of load served by each LSE in an Electric Distributor's territory, PJMSettlement utilizes the information submitted into PJM's internal energy scheduling tool by LSEs and Electric Distributors for their respective load contracts, including the names of the LSE responsible for serving the load and the Electric Distributor in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the Energy Settlement Area at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified Energy Settlement Area is further assigned to individual load buses included in the Energy Settlement Area, based on the definition for the Energy Settlement Area as defined in Section 31.7 of the PJM Tariff, which specifies the percentage of the Energy Settlement Area that each bus represents, to identify the LSE's hourly megawatts of load at each bus. All megawatts of load assigned to LSEs in an Electric Distributor's territory as described herein are subtracted from the total megawatts of load for which the Electric Distributor is responsible as determined in subsection (e)(i) above.

(iii) Electric Distributors that hold POLR auctions or similar load auctions may direct PJM to automatically assign megawatt hours for which the Electric Distributor is responsible, as determined in subsection (e)(ii) above, to the POLR Suppliers based on the tranches the POLR Suppliers won in the auction, as a billing service, based on their contracts associated with the POLR load programs. In such case, the POLR Supplier's share of load shall be determined by multiplying the megawatt hours at each bus that were not specifically assigned under load contracts by the percentage of load won by the POLR Supplier in proportion to its share of the total POLR load of the Electric Distributor. This billing service may also apply to Electric Distributors and LSEs that mutually agree upon a transfer of load from the EDC to the LSE based upon a specified percentage of the megawatt hours at each bus that were not specifically assigned under load contracts.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Price determined in accordance with the Day-ahead

Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation bus or Interface Pricing Point in any hour is less than the energy scheduled to be injected at that bus or point in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus or point at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation buses or Interface Pricing Points.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-

to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region.

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule.

5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

6. "MUST-RUN" FOR RELIABILITY GENERATION

6.1 Introduction.

The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

6.2 Identification of Facility Outages.

Not later than one hour prior to the deadline specified in Section 1.10.1 of this Schedule, the Office of the Interconnection shall identify on the PJM Open Access Same-Time Information System any facility outage or other system condition which it has determined may give rise to a transmission constraint that may require, in order to maintain system reliability, the dispatch of one or more generation resources that otherwise would not be dispatched based on the merits of their offers to the PJM Interchange Energy Market.

6.3 Dispatch for Local Reliability.

6.3.1 Request and Dispatch.

In addition to the dispatch of generation by the Office of the Interconnection to maintain reliability on transmission facilities monitored by it, a Member that owns or leases with rights equivalent to ownership local Transmission Facilities, as defined in this Agreement and the Consolidated Transmission Owners Agreement and that operates a local control center in accordance with Section 11.3.3 of this Agreement or a Market Operations Center in accordance with Section 1.7.5 of this Schedule may request the Office of the Interconnection to dispatch generation in order to maintain reliability on any such local Transmission Facilities that are not then monitored by the Office of the Interconnection, subject to the rules and procedures in Section 6.3.2 and the PJM Manuals. The Office of the Interconnection shall dispatch generation to maintain reliability on such local Transmission Facilities by incorporating the facilities in the State Estimator program described in Section 2.3 as set forth below, unless the Office of the Interconnection determines that such dispatch would adversely affect reliability in the PJM Region or would otherwise not be in accordance with Good Utility Practice.

6.3.2 Designation of Local Transmission Facilities.

The following rules and procedures shall apply to a Member request that the Office of the Interconnection dispatch generation on one or more local Transmission Facilities that are not then directly monitored by the Office of the Interconnection.

- (a) The local Transmission Facilities that are the subject of the request for monitoring and dispatch control must be among the facilities that comprise the Transmission System under the PJM Tariff and must meet the PJM Reliability Planning Criteria set forth in the PJM Manuals;
- (b) The Member shall provide modeling information for such local Transmission Facilities and provide sufficient telemetry to the Office of the Interconnection such that power flows are observable by the State Estimator program described in Section 2.3;
- (c) The request for monitoring and dispatch control of local Transmission Facilities shall constitute a request that such local Transmission Facilities become and remain monitored by the Office of the Interconnection and subject to its dispatch control for a period of not less than one year;
- (d) Requests under this Section for monitoring and dispatch control of local Transmission Facilities may be made only annually pursuant to the procedures set forth in the PJM Manuals;
- (e) The Office of the Interconnection shall post all requests for monitoring and dispatch control of local Transmission Facilities made under this Section on the PJM Internet site; and
- (f) The Member shall comply with all other operating procedures established by the Office of the Interconnection regarding dispatch for local reliability as set forth in the PJM Manuals.

6.3.3 Transition Procedures for Local Transmission Facilities under the Monitoring Responsibility and Dispatch Control of the Office of the Interconnection as of June 1, 2002.

The Office of the Interconnection shall determine whether local Transmission Facilities under its monitoring responsibility and dispatch control as of June 1, 2002 meet the PJM Reliability and Planning Criteria. Members with such local Transmission Facilities that do not meet the PJM Reliability Planning Criteria must either (1) remove the local Transmission Facilities from the dispatch control and monitoring responsibility of the Office of the Interconnection within 60 days of notification by the Office of the Interconnection of its determination that the local Transmission Facilities do not meet the PJM Reliability and Planning Criteria; or (2) commit, at their own cost and by a completion date agreed to by the Office of the Interconnection and the Member, to reinforce the local Transmission Facilities to enable the local Transmission Facilities to meet the PJM Reliability and Planning Criteria. This commitment to reinforce the local Transmission Facilities is subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, provided that, in the event that a Member cannot reinforce the local Transmission Facilities due to the unavailability of required financing, the local Transmission Facilities must be removed from the monitoring responsibility and dispatch control of the Office of the Interconnection within 60 days of the determination that required financing is unavailable. The local Transmission Facilities will remain under the monitoring and dispatch control of the Office of the Interconnection during the construction of the reinforcements.

6.4 Offer Price Caps.

6.4.1 Applicability.

- (a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped at the levels specified below. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the transmission limit affects the schedule of the affected resource, and otherwise shall be capped for the entire Operating Day. The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Sections 2.2 and 2.4 of this Schedule.
- (b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified below. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. The energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.
- (c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.
- (d) [Reserved for Future Use]
- (e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any hour in which (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the generation resource's owner, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test").
- (f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:
 - (i) All megawatts of available incremental supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

- (ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.
- (iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.
- (iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

6.4.2 Level.

- (a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:
 - (i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;
 - (ii) For offers of \$2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus up to 10% of such costs, the sum of which shall not exceed \$2,000/MWh; and, for offers greater than \$2,000/MWh, the incremental cost of the generation resource;
 - (iii) For units that are frequently offer capped ("Frequently Mitigated Unit" or "FMU"), and for which the unit's price based offer was greater than its

cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus \$20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus \$30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus \$40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

- (i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.
- (ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in \$/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in \$/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in \$/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)
- (iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.
- (iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

- 1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder;
3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.5 [Reserved for Future Use]

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations (“parameter limited schedules”) under the following circumstances:

- (i) The Market Seller fails the three pivotal supplier test. When this subsection applies, the parameter limited schedule shall be the less limiting, i.e. more flexible, of the defined parameter limited schedules or the submitted offer parameters.
- (ii) For the 2014/2015 through 2017/2018 Delivery Years, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all, or any part, of an Operating Day.
- (iii) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.
- (iv) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations, for all, or any part, of an Operating Day.

(b) For the 2014/2015 through 2017/2018 Delivery Years *for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2019/2020 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan*, parameter limited schedules shall be defined for the following parameters:

- (i) Turn Down Ratio;
- (ii) Minimum Down Time;
- (iii) Minimum Run Time;

- (iv) Maximum Daily Starts;
- (v) Maximum Weekly Starts.

For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources during Hot Weather Alerts, Emergency Actions during hot weather operations, and when the unit is offer capped to maintain system reliability as a result of limits on transmission capability per Section 6.4 hereof, and for the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources during Hot Weather Alerts, Cold Weather Alerts, Emergency Actions, and when the unit is offer capped to maintain system reliability as a result of limits on transmission capability per Section 6.4 hereof, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

- (i) Turn Down Ratio;
- (ii) Minimum Down Time;
- (iii) Minimum Run Time;
- (iv) Maximum Daily Starts;
- (v) Maximum Weekly Starts;
- (vi) Maximum Run Time;
- (vii) Start-up Time; and
- (viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (h) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. *In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.*

(c) For the 2014/2015 through 2017/2018 Delivery Years, the following table specifies default parameter limited schedule values, by technology type, for generating units, no portion of which is committed as a Capacity Performance Resource:

Parameter Limited Schedule Matrix

Parameter	Minimum Down Time (Hrs)	Minimum Run Time (Hrs)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio = Economic Maximum MW / Economic Minimum MW
Small Frame CT and Aero CT Units - Up to 29 MW ICAP	2.0 or Less	2.0 or Less	2 or More	14 or More	1.0 or More
Medium Frame CT and Aero CT Units - 30 MW to 65 MW ICAP	2.0 or Less	3.0 or Less	2 or More	14 or More	1.0 or More
Medium-Large Frame CT Units - 65 MW to 135 MW ICAP	3.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Large Frame CT Units - 135 MW to 180 MW ICAP	4.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Combined Cycle Units	4.0 or Less	6.0 or Less	2 or More	11 or More	1.5 or More
Petroleum and Natural Gas Steam Units - Pre-1985	7.0 or Less	8.0 or Less	1 or More	7 or More	3.0 or More
Petroleum and Natural Gas Steam Units - Post-1985	3.5 or Less	5.5 or Less	2 or More	11 or More	2.0 or More
Sub-Critical Coal Units	9.0 or Less	15.0 or Less	1 or More	5 or More	2.0 or More
Super-Critical Coal Units	84.0	24.0 or Less	1 or More	2 or More	1.5 or More

(d) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in section II.B.1 of Attachment M - Appendix,

the Office of the Interconnection shall file to revise the Parameter Limited Schedule Matrix in section 6.6(c) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate.

(e) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with section II.B of Attachment M - Appendix. The default values set forth in the table in subsection (c) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (h) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.

(f) For the 2016/2017 Delivery Year and subsequent Delivery Years, the following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (b) above:

- (i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;
- (ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;
- (iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,
- (iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (b) above:

- (i) Have combined start-up and notification times that shall not exceed one hour; and,
- (ii) Have a minimum down time that shall not exceed one hour.

(g) For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (b) above:

- (i) Combined start-up and notification times shall not exceed 48 hours;
- (ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and,
- (iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.

(h) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

- (i) *Temporary Exceptions.* A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, at least one business day prior to the commencement of the exception, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three business days after such request. Failure to provide a timely response to such request for additional

information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one business day prior to the early termination date. A temporary exception may only be requested one-time for the same physical or actual constraint since an operational constraint that may occur more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three business days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Section II.B of Attachment M-Appendix, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 business days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 business days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) *Period Exceptions and Persistent Exceptions.* Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Section II.B of Attachment M - Appendix. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller's request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 business days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 business days after receipt of the Market Seller's notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff

or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

- (1) for generating units for which no megawatts of the unit are committed as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years,
- (2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years,
- (3) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years,
- (4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and
- (5) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years.

(i) Notwithstanding the foregoing, the provisions of this Section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner's obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(j) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a

generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(k) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

6A [Reserved For Future Use]

6A.1 [Reserved For Future Use]

6A.2 [Reserved For Future Use]

6A.3 [Reserved For Future Use]

7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to Section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to Section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to Section 5.2.2(e) and the award of Financial Transmission Rights pursuant to Section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction. An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to Section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual Financial Transmission Rights auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term Financial Transmission Rights auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term Financial Transmission Rights auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term FTR auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of three rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 3 months after the first round, and the third round shall be conducted approximately 3 months after the second round. In each round 1/3 of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three business days ending at 5:00 p.m. on the last day. PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five business days after the close of the bidding period for each round unless circumstances beyond PJM's control prevent PJM from meeting the applicable deadline. Under such circumstances, PJM will post the auction results at the earliest possible opportunity. If the Office of the Interconnection discovers an error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no

later than 5:00 p.m. of the second business day following the initial publication of prices for that auction. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

- (i) The periods covered by long-term Financial Transmission Rights auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.
- (ii) On-Peak, off-peak and 24-hour Financial Transmission Rights obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

- (i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights Auction. Eligible receipt and delivery points in long-term Financial Transmission Rights Auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.2 Financial Transmission Rights Characteristics.

7.2.1 Reconfiguration of Financial Transmission Rights.

Through an appropriate linear programming model, the Office of the Interconnection shall reconfigure the Financial Transmission Rights offered or otherwise available for sale in any auction to maximize the value to the bidders of the Financial Transmission Rights sold, provided that any Financial Transmission Rights acquired at auction shall be simultaneously feasible in combination with those Financial Transmission Rights outstanding at the time of the auction and not sold in the auction. The linear programming model shall, while respecting transmission constraints and the maximum MW quantities of the bids and offers, select the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers.

7.2.2 Specified Receipt and Delivery Points.

The Office of the Interconnection will post the list of available receipt and delivery points for each Financial Transmission Rights Auction before the start of the bidding window. Auction bids for annual Financial Transmission Rights Obligations may specify as receipt and delivery points any combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points. Auction bids for annual Financial Transmission Rights Options may specify as receipt and delivery points such combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points as the Office of the Interconnection shall allow from time to time as set forth in PJM Manual 06: Financial Transmission Rights. Auction bids for Financial Transmission Rights submitted in the monthly auctions may specify as receipt and delivery points any combination of available hubs, Zones, aggregates, generators, and Interface Pricing Points for bids that cover any month beyond the next month, including bids that cover Planning Period Quarters or the Planning Period Balance. Auction bids for Financial Transmission Rights submitted in the monthly auctions that cover the single calendar month period immediately following the month in which the monthly auction is conducted may specify any combination of available receipt and delivery buses represented in the State Estimator model for which the Office of the Interconnection calculates and posts Locational Marginal Prices. Auction bids may specify available receipt and delivery points from locations outside of the PJM Region to locations inside such region, from locations within the PJM Region to locations outside such region, or to and from locations within the PJM Region.

7.2.3 Transmission Congestion Charges.

Financial Transmission Rights shall entitle holders thereof to credits only for Transmission Congestion Charges, and shall not confer a right to credits for payments arising from or relating to transmission congestion made to any entity other than PJMSettlement.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Financial Transmission Rights auctions conducted to liquidate a defaulting Members' Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in the Section 7.3.9 herein and with the standards and procedures set forth in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offer or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period,

market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

- (a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.
- (b) In accordance with the requirements of Section 7.5 of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.
- (c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints. Financial Transmission Rights with a zero clearing price will only be awarded if there is a minimum of one binding constraint in the auction period for which the Financial Transmission Rights path sensitivity is non-zero.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at

which each Financial Transmission Right was awarded unless circumstances beyond PJM's control prevent PJM from meeting the applicable deadline. Under such circumstances, PJM will post the auction results at the earliest possible opportunity. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.3.9 Liquidation of Financial Transmission Rights in the Event of Member Default.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the PJM Operating Agreement or PJM Tariff, the Office of the Interconnection shall, as soon as practicable after such default is declared, initiate the following procedures to close out and liquidate the Financial Transmission Rights of a Member:

- a) The Office of the Interconnection shall close out the defaulting Member's positions as of the date of its default, by unilaterally accelerating and terminating all forward Financial Transmission Rights positions.
- b) The Office of the Interconnection shall post on its website all salient information relating to the closed out portfolio of Financial Transmission Rights.
- c) All current planning period Financial Transmission Right positions within the defaulting Members' Financial Transmission Right portfolio will be offered for sale in the next available monthly balance of planning period Financial Transmission Rights auction at an offer price designed to maximize the likelihood of liquidation of those positions.

d) Financial Transmission Rights positions that do not settle until the next or subsequent planning period will be offered into the next available Financial Transmission Rights auction (taking into account timing constraints and the need for an orderly liquidation) where, based on the Office of Interconnection's commercially reasonable expectation, such positions would be expected to clear. In the event that the next scheduled Financial Transmission Rights auction is more than two (2) months subsequent to the date that the Office of the Interconnection declares a Member in default, a specially scheduled Financial Transmission Rights auction may be conducted by the Office of the Interconnection. The entire portfolio of the defaulting Member's Financial Transmission Rights will be offered for sale at an offer price designed to maximize the likelihood of liquidation of those positions.

e) The Financial Transmission Right positions comprising the defaulting Member's portfolio that are liquidated in a Financial Transmission Rights auction should avoid setting the price in the auction at the bid prices with which they were initially submitted. In the event that any of the closed out Financial Transmission Rights would set price based on the auction's preliminary solution, then only one-half of each Financial Transmission Rights position will be offered for sale and the auction will be re-executed. In the event that any Financial Transmission Rights position that has been closed out once again sets price, then all Financial Transmission Rights scheduled to be liquidated will be removed from the affected auction and the auction will be re-executed excluding the closed out Financial Transmission Right positions. Financial Transmission Right positions that are not liquidated will then be offered in the next available auction or specially scheduled auction, as appropriate.

f) The liquidation of the defaulting Members' Financial Transmission Rights portfolio pursuant to the foregoing procedures shall result in a final liquidated settlement amount. The final liquidated settlement amount will be included in calculating a Default Allocation Assessment as described in Section 15.1.2A(I) of the PJM Operating Agreement. If the Office of the Interconnection is unable to close out and liquidate a Financial Transmission Rights position under the foregoing procedures, the close out shall be deemed void and the defaulting Member shall remain liable for the full final value of its default, such full final value being realized at the normal time for performance of the Financial Transmission Rights position.

In all other respects, Financial Transmission Rights terminated pursuant to this section shall be liquidated pursuant to the appropriate provisions and procedures set forth in the PJM Manuals.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

- (a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.
- (b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.
- (c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:
 - (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
 - (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
 - (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.
- (d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:
 - (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

- (ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

- (a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

- (b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; 2011 for the ATSI Zone; 2012 for the DEOK Zone; 2013 for the EKPC Zone; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each

historical generation resource in a number of megawatts equal to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Prior to the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right allocated to a Network Service User shall be to the Energy Settlement Area of such Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights allocated at the aggregate load buses in a Zone. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section

7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Prior to the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff. Commencing with the 2015/2016 Planning Period, each Auction Revenue Right shall sink to the Energy Settlement Area of the Network Service User as described in Section 31.7 of Part III of the Tariff, unless the Network Service User's Energy Settlement Area represents the Residual Metered Load of an electric distribution company's fully metered franchise area(s) or service territory(ies) and the Network Service User elects to have its Auction Revenue Rights sink at the aggregate load buses in a Zone. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under

contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARR/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible unless such infeasibility is caused by extraordinary circumstances. Such increased limits shall be included in all rounds of the annual allocation and auction processes and in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (i) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission

Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (i), extraordinary circumstances shall mean an unanticipated event outside the control of PJM that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

- i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.
- ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.
- iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.
- iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

- v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.
- vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).
- vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.
- viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.
- ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.
- x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.
- xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.
- xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights

megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

- xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).
- xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.
- xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.
- xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

- (a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.
- (b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.
- (c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the

bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

- (a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.
- (b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.
- (c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.5 Simultaneous Feasibility.

(a) The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate powerflow models of contingency-constrained dispatch. Such determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction that are not inconsistent with the determination of the deliverability of Generation Capacity Resources under the Reliability Assurance Agreement. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all Financial Transmission Rights Obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights obligations.

(b) On an annual basis the Office of the Interconnection shall conduct a simultaneous feasibility test for stage 1A Auction Revenue Rights, which shall assess the simultaneous feasibility for each year remaining in the term of the right(s). This test shall be based on the Auction Revenue Rights required to meet Zonal Base Load requirements. The Office of the Interconnection shall apply a zonal load growth rate to the simultaneous feasibility test for the ten year term of the stage 1A Auction Revenue Rights to reflect load growth as estimated by the Office of the Interconnection.

(c) Simultaneous feasibility tests for new stage 1 resource requests made pursuant to Section 7.6 of Schedule 1 of this Agreement shall ensure that the request for a new base resource does not increase the megawatt flow on facilities binding in the current Auction Revenue Rights allocation or in future stage 1A allocations and does not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions. The most limiting set of conditions will be used as the limiting condition in these evaluations. A simultaneous feasibility test conducted pursuant to this section by the Office of the Interconnection shall assess the simultaneous feasibility under the following conditions:

- Based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs.
- Based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

(d) Simultaneous feasibility tests conducted pursuant to this section shall be subject to Incremental Auction Revenue Rights granted pursuant to Section 7.8 of Schedule 1 of this Agreement and Section 231 of the PJM Tariff.

7.6 New Stage 1 Resources.

A Network Service User may request the addition of new stage 1 resources to the stage 1 resource list if the capacity of the historical generation resources for a Zone determined pursuant to Section 7.4.2(b) is less than the Zonal Base Load. Requests made pursuant to this section shall be subject to Section 7.5(c) of Schedule 1 of this Agreement and shall be limited to generation resources either owned by the requesting party or those subject to a bona fide firm energy and capacity supply contracts where such contract is executed by the requesting party to meet load obligations for which it is eligible to receive stage 1 Auction Revenue Rights and remains in force and effect for a minimum term of ten (10) years.

7.7 Alternate Stage 1 Resources.

A Network Service User may replace one or more of its existing stage 1 resources and its associated megawatt amount of Auction Revenue Rights determined pursuant to Section 7.4.2(b) with an alternate resource. If the Network Service User making such request accepts the megawatt amount of Auction Revenue Rights associated with the alternate resource as established by the Office of the Interconnection, the alternate resource shall replace the relevant existing stage 1 resource prospectively beginning with the next annual Auction Revenue Rights allocation. If the Network Service User making such request rejects the megawatt amount of Auction Revenue Rights established by the Office of the Interconnection for the alternate resource, the Auction Revenue Rights associated with the original stage 1 resource shall remain in effect for the Network Service User. Requests made pursuant to this section shall be subject to the following:

- Requests made pursuant to this section shall be subject to Section 7.5(c);
- Eligible alternate resources shall be limited to generation resources owned by the requesting party or bona fide firm energy and capacity supply contracts that meet the requirements set forth in Section 7.6 of Schedule 1 of this Agreement;
- Alternate resources shall be of an electrically equivalent megawatt amount, which means that relative to the existing resource, the alternate resource cannot consume a greater amount of transmission capability on facilities binding in the current Auction Revenue Rights allocation or future stage 1A allocations, and cannot allow megawatt flow(s) to exceed applicable ratings on any other facilities;
- The total amount of requested alternate stage 1 Auction Revenue Rights cannot exceed the original awarded stage 1 megawatt amounts of Auction Revenue Rights associated with the original historical resource as determined pursuant to Section 7.4.2(b).

7.8 Elective Upgrade Auction Revenue Rights.

- (a) In addition to any Incremental Auction Revenue Rights (as defined in the PJM Tariff) established under the PJM Tariff, any party may elect to fully fund Network Upgrades (as defined in the PJM Tariff) to obtain Incremental Auction Revenue Rights pursuant to this section, provided that Incremental Auction Revenue Rights granted pursuant to this section shall be simultaneously feasible with outstanding Auction Revenue Rights, which shall include stage 1 and stage 2 Auction Revenue Rights, and against stage 1A Auction Revenue Right capability for the future 10 year period, as determined by the Office of the Interconnection pursuant to Section 7.8(b) of Schedule 1 of this Agreement. A request made pursuant to this section shall specify a source, sink and megawatt amount.
- (b) The Office of the Interconnection shall assess the simultaneous feasibility of the requested Incremental Auction Revenue Rights and the outstanding Auction Revenue Rights against the existing base system Auction Revenue Right capability and stage 1A Auction Revenue Right capability for the future 10 year period and based on this preliminary assessment it shall conduct studies to determine the upgrades required to accommodate the requested Incremental Auction Revenue Rights and ensure all outstanding Auction Revenue Rights are simultaneously feasible.
- (c) If a party elects to fund upgrades to obtain Incremental Auction Revenue Rights pursuant to this section, no less than forty-five (45) days prior to the in-service date of the relevant upgrades, as determined by the Office of the Interconnection, the Office of the Interconnection shall notify the party of the actual amount of Incremental Auction Revenue Rights that will be granted to the party based on the allocation process established pursuant to Section 231 of Part VI of the Tariff.
- (d) Incremental Auction Revenue Rights established pursuant to this section shall be effective for the lesser of thirty (30) years, or the life of the project, from the in-service date of the Network Upgrade(s). At any time during this thirty-year period (or the life of the Network Upgrade whichever is less), in lieu of continuing this thirty-year Auction Revenue Right, the owner of the right shall have a one-time choice to switch to an optional mechanism, whereby, on an annual basis, it will have the choice to request an Auction Revenue Right during the annual Auction Revenue Rights allocation process between the same source and sink, provided the Auction Revenue Right is simultaneously feasible. A party that is granted Incremental Auction Revenue Rights pursuant to this section may return such rights at any time, provided that the Office of the Interconnection determines that it can simultaneously accommodate all remaining outstanding Auction Revenue Rights following the return of such Auction Revenue Rights. In the event a party returns Incremental Auction Revenue Rights, it shall retain no further rights regarding such Incremental Auction Revenue Rights.
- (e) No Incremental Auction Revenue Rights shall be granted pursuant to this section if the costs associated with funding the associated Network Upgrades are included in the rate base of a public utility and on which a regulated return is earned.

7.9 Residual Auction Revenue Rights.

- (a) As necessary in each Planning Period PJM shall calculate Residual Auction Revenue Rights for Auction Revenue Rights pathways that were prorated pursuant to section 7.4.2(h) of Schedule 1 of this Agreement. Residual Auction Revenue Rights calculated pursuant to this section shall be determined prior to the increase in transmission capability, including the return to service of existing transmission capability, that creates the Residual Auction Revenue Rights.
- (b) Network Service Users and Qualifying Transmission Customers allocated stage 1 Auction Revenue Rights pursuant to section 7.4.2(a)-(c) of Schedule 1 of this Agreement that were subject to proration pursuant to section 7.4.2(h) of Schedule 1 of this Agreement shall be eligible to receive Residual Auction Revenue Rights. Residual Auction Revenue Rights shall be allocated pursuant to the following schedule:
- (i) The initial allocation of Residual Auction Revenue Rights shall be to holders of prorated stage 1A Auction Revenue Rights in an amount equal to the difference between the allocated stage 1A Auction Revenue Rights and the requested stage 1A Auction Revenue Rights.
 - (ii) Residual Auction Revenue Rights remaining after an allocation made pursuant to section 7.9(b)(i) of Schedule 1 of this Agreement shall be allocated to holders of prorated stage 1B Auction Revenue Rights in an amount equal to the difference between the allocated stage 1B Auction Revenue Rights and the requested stage 1B Auction Revenue Rights.
 - (iii) Residual Auction Revenue Rights remaining after allocations made pursuant to section 7.9(b)(i) and (ii) of Schedule 1 of this Agreement shall not be allocated to any entity and shall not be considered by the Office of the Interconnection in its administration of Section 7 of Schedule 1 of this Agreement.
- (c) The sum of a Network Service User's and Qualifying Transmission Customer's Residual Auction Revenue Rights awarded pursuant to this section and its stage 1 and 2 Auction Revenue Rights awarded in an annual allocation shall not exceed the entity's peak load.
- (d) Residual Auction Revenue Rights awarded pursuant to this section shall be effective on the first day of the month in a Planning Period the increase in transmission capability creating the Residual Auction Revenue Rights is included in the administration of section 7.1.1(a) of Schedule 1 of this Agreement.
- (e) Residual Auction Revenue Rights awarded pursuant to this section shall be subject to section 7.4.2(e) of Schedule 1 of this Agreement.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM

8.1 Emergency Load Response and Pre-Emergency Load Response Program Options

The Emergency Load Response Program and Pre-Emergency Load Response Program are designed to provide a method by which end-use customers may be compensated by PJM for reducing load immediately prior to an anticipated emergency event (“pre-emergency event”) or during an emergency event. As used in the Emergency Load Response Program and Pre-Emergency Load Response Program, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program and Pre-Emergency Load Response Program:

- ◆ **Full Program Option**

Participants in the Full Program Option receive, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for load reductions during a pre-emergency event or emergency event measured as set forth in the Reporting and Compliance provisions below.

- ◆ **Energy Only Option**

Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

8.2 Participant Qualifications

Two primary types of distributed resources are candidates to participate in the PJM Emergency Load Response Program and Pre-Emergency Load Response Program:

On Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

Only Members or Special Members may participate in the Emergency Load Response Program and Pre-Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response and Pre-Emergency Load Response Program provisions herein, including, but not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member or Special Member may participate in the Emergency Load Response Program and Pre-Emergency Load Response Program on behalf of non-members as the Curtailment Service Provider. All payments are made to the PJM Member or Special Member in such case. Curtailment Service Providers must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** However, for Special Members the \$5,000 annual member fee, the \$1,500 application fee, and liability for Member defaults are waived, along with the following other modifications.

- Special Members are limited to be PJM Market Sellers;
- Voting privileges and sector designation are waived;
- Thirty day notice for waiting period is waived;
- Requirement for 24/7 control center coverage is waived;
- No PJM-supported user group capability is permitted.

To participate in the Emergency Load Response Program and Pre-Emergency Load Response Program, the Demand Resource must:

- Be capable of reducing at least 100 kW of load;
- Be capable of receiving notification of a Load Management Event.

8.3 Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program and Pre-Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. Non-interval metered residential customers that have Direct Load Control may use current statistical sampling of interval metering equipment on an electric distribution company account basis in accordance with the PJM Manuals and subject to PJM approval. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Program and Pre-Emergency Load Response Program participants must meter reductions in demand by using either of the following two methods:

- (a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or
- (b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis, or metered on a representative sample of Electric Distribution Company accounts for non-interval metered residential Direct Load Control in accordance with the PJM Manuals.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

- (a) Metering equipment used for retail electric service;
- (b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM in accordance with the requirements herein and in the PJM Manuals; or
- (c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

8.4 Registration

1. Curtailment Service Providers must complete the applicable PJM Load Response Program Registration Form ("Registration Form") that is posted on the PJM website (www.pjm.com) for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company ten business day review period, as described herein, Curtailment Service Providers should submit completed Registration Forms to the Office of the Interconnection no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery Year shall be rejected by the Office of the Interconnection. To the extent that a completed Registration Form is submitted to the Office of the Interconnection prior to one day before the tenth business day preceding the relevant Delivery Year and such registration is rejected by the electric distribution company or the Office of the Interconnection because of incorrect data on the Registration Form, such registration may be resubmitted by the Curtailment Service Provider before May 31st preceding the relevant Delivery Year, but such registration will be rejected by the Office of the Interconnection unless the electric distribution company has verified the registration on or before May 31st preceding the relevant Delivery Year. Incomplete Registration Forms will be rejected by the Office of the Interconnection; Curtailment Service Providers may not resubmit registrations that were rejected for being incomplete unless they are able to do so no later than one day before the tenth business day preceding the relevant Delivery Year. The following general steps will be followed:

2. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. The Curtailment Service Provider completes the Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response or Pre-Emergency Load Response Program participant, PJM shall notify the appropriate electric distribution company of an Emergency Load Response and Pre-Emergency Load Response Program participant's registration and request verification as to whether the load that may be reduced is subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response Programs pursuant to the process described below. The electric distribution company has ten business days to respond. An electric distribution company which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company asserts has not been satisfied) an end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting

to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

- i. If evidence provided by an electric distribution company to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after May 31st preceding the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.
 - b. In the absence of a response from the electric distribution company within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response and Pre-Emergency Load Response Programs, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response and Pre-Emergency Load Response Program requirements.
 - c. For those registrations terminated pursuant to this section, all Emergency Load Response and Pre-Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJM in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.
3. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. The Curtailment Service Provider completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response and Pre-Emergency Load Response participant, PJM shall notify the appropriate electric distribution company of an Emergency Load Response and Pre-Emergency Load Response participant's registration and request verification as to whether the load that may be reduced is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company has ten business days to respond. If the electric distribution company verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company asserts has been satisfied) to participate in the Emergency Load Response Program and Pre-Emergency Load Response Program, then the electric distribution company must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. If the electric distribution company denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration on or before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

b. In the absence of a response from the electric distribution company within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with all of the Emergency Load Response and Pre-Emergency Load Response Program requirements, including the registration section, the Emergency Load Response and Pre-Emergency Load Response participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response and Pre-Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency Load Response and Pre-Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

4. PJM will inform the requesting Curtailment Service Provider of acceptance into the Emergency Load Response Program and Pre-Emergency Load Response Program and notify the appropriate electric distribution company of the requesting Curtailment Service Provider's acceptance into the program or notifies the requesting Curtailment Service Provider and appropriate electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

8.5 Pre-Emergency Operations

All participants in the Pre-Emergency Load Response Program shall be subject to the operation procedures herein, unless the participant can demonstrate its Demand Resource: (1) relies on Behind the Meter generation to fulfill its load reduction obligations; (2) the Demand Resource has environmental restrictions imposed on it by Applicable Laws and Regulations that limit the Demand Resource's ability to operate only in emergency conditions; and (3) such limitation exists for any period of time. For the purposes of Section 8, emergency conditions shall be defined either by the express terms of the Applicable Law or Regulation, or if not set forth therein shall be deemed to exist if PJM has declared a NERC Energy Emergency Alert Level 2, as defined in the applicable NERC Standards. If these criteria are met, the participant shall be subject to the emergency operation procedures contained in Section 8.6. In such case, the Curtailment Service Provider shall submit a request for the relevant Demand Resource(s) to be an emergency (versus pre-emergency) Demand Resource to the Office of the Interconnection, at the time the Registration Form is submitted in accordance with this Agreement. A Curtailment Service Provider shall not submit a request for an exception unless it has done its due diligence to confirm that the Demand Resource meets the requirements referenced herein and has obtained from the end-use customer documentation supporting the exception request. The Curtailment Service Provider shall provide the Office of the Interconnection with a copy of such supporting documentation within three (3) business days of a request therefor. Failure to provide such supporting documentation by the deadline shall result in the Demand Resource being subject to the pre-emergency procedures herein.

PJM will initiate a pre-emergency event prior to the declaration of a Maximum Generation Emergency or an emergency event when practicable. A pre-emergency event is implemented when economic resources are not adequate to serve load and maintain reserves or maintain system reliability, and prior to proceeding into emergency procedures. Understanding the primary responsibility of the Office of the Interconnection to maintain system security, the Office of the Interconnection will strive to exhaust, but it is not obligated to exhaust, all economic resources prior to initiating a pre-emergency event. PJM will initiate an electronic message to Curtailment Service Providers notifying them of the pre-emergency event; Curtailment Service Providers are required to have the capability to retrieve this electronic message as described in the PJM Manuals. Additionally, PJM will post the pre-emergency event information on the PJM website and issue a separate All-Call message.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the availability, location, minimum notification time, dispatch price and/or quantity of load reduction needed, subject to transmission constraints in the PJM Region. To give PJM dispatchers the flexibility to address reliability concerns in the most effective and timely manner and invoke the resources that offer the most assurance of effective relief of emergency conditions, the dispatch of Demand Resources may not be based solely on the least-cost resources since such dispatch shall be based not only on price, but also on availability, location, minimum notification time and/or quantity of megawatts of load or load reduction needed.

The dispatch price of Full Program Option resources and Energy Only Option resources in the Pre-Emergency Load Response Program are eligible to set the real time Locational Marginal Prices (“LMP”) when the Office of the Interconnection has implemented pre-emergency procedures and such resources are required to reduce demand in the PJM Region and as described in Section 2 of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K-Appendix of the PJM Tariff. Energy Only Option resources must also satisfy PJM’s telemetry requirements.

Curtailement Service Providers with resources registered to participate in the Emergency Load Response and Pre-Emergency Load Response Programs must provide real-time operational data regarding the availability and status of their resources to PJM, and comply with operational procedures, as described in detail in the PJM Manuals.

8.6 Emergency Operations

PJM will initiate the notification of a Load Management Event coincident with the declaration of Maximum Generation emergency. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) A Load Management Event is implemented whenever economic generating capacity is not adequate to serve load and maintain reserves or maintain system reliability. PJM will initiate an electronic message to Curtailment Service Providers notifying them of the Load Management Event; Curtailment Service Providers are required to have the capability to retrieve this electronic message as described in the PJM Manuals. Additionally, PJM will post the Load Management Event information on the PJM website and issue a separate All-Call message.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the availability, location, minimum notification time, dispatch price and/or quantity of load reduction needed, subject to transmission constraints in the PJM Region. To give PJM dispatchers the flexibility to address reliability concerns in the most effective and timely manner and invoke the resources that offer the most assurance of effective relief of emergency conditions, the dispatch of Demand Resources may not be based solely on the least-cost resources since such dispatch shall be based not only on price, but also on availability, location, minimum notification time and/or quantity of megawatts of load or load reduction needed.

The dispatch price of Full Program Option resources and Energy Only Option resources in the Emergency Load Response Program are eligible to set the real time LMP when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region and as described in Section 2 of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K-Appendix of the PJM Tariff. Energy Only Option resources must also satisfy PJM's telemetry requirements.

Curtailment Service Providers with resources registered to participate in the Emergency Load Response and Pre-Emergency Load Response Programs must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations***.

8.7 Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the Load Management Event. If the data are not received within 60 days, no payment for participation shall be provided. Meter data must be provided for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the electric distribution company upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The minimum duration of a load reduction request is one hour. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form. Compensation will be provided for reductions in energy consumption during emergency events by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing Operating Reserve charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping

dispatch hours for an aggregate registration (i.e., multiple locations on the same registration) or dispatch groups where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Programs are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

8.9 Reporting and Compliance

Actual load reductions of Energy Only Option emergency resources will be added back for the purpose of peak load calculations for capacity for the following Delivery Year.

Actual Emergency Load Response, Pre-Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Load Response or Pre-Emergency Load Response Full Program Option or Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year, as set forth in the PJM Manuals and consistent with the load response recognized for capacity compliance as set forth in the Reporting and Compliance provisions below. Capacity Only resources are Full Program Option resources that do not receive an energy payment for load reductions during a pre-emergency or emergency event.

Actual load reductions of Load Management resources registered as Emergency Load Response or Pre-Emergency Load Response Full Program Option or Capacity Only resources used to determine Load Management Event and test capacity compliance for Firm Service Level and Guaranteed Load Drop end-use customers shall be equal to the load reduction provided to the electric distribution company as follows and in accordance with the PJM Manuals:

- i) For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if the Office of the Interconnection did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF"). A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution. The calculation is represented by:

Minimum of $\{(\text{comparison load} - \text{Load}) * \text{LF}, \text{PLC} - (\text{Load} * \text{LF})\}$

Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers include the following:

- ◆ Comparable Day
- ◆ Same Day
- ◆ Customer Baseline
- ◆ Regression Analysis
- ◆ Generation

Each of these methodologies is described in greater detail in Manual M-19, ***PJM Manual for Load Forecasting and Analysis***, at Attachment A: Load Drop Estimate Guidelines.

- ii) For Firm Service Level end-use customers the current Delivery Year PLC minus the Load multiplied by the LF. The calculation is represented by:

$$\text{PLC} - (\text{Load} * \text{LF})$$

The capacity compliance of Load Management resources that are registered as Emergency Load Response and Pre-Emergency Load Response Full Program Option, as determined in accordance with these Reporting and Compliance provisions, shall not affect energy payments to such resources for load reductions during an emergency event, as provided in the Market Settlements provisions above and Attachment DD of the Tariff.

PJM will submit any required reports to FERC on behalf of the Emergency Load Response and Pre-Emergency Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies pursuant to section 1.5A.3 of PJM's Economic Load Response Program, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies assert prohibit or condition retail participation in PJM's Emergency Load Response and Pre-Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies.

8.10 Non-Hourly Metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The Curtailment Service Provider must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response and Pre-Emergency Load Response Programs that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response and Pre-Emergency Load Response Participant aggregations shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company ;
- iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;
- iv. Energy settlement will be based on each individual customer's load reductions, or a current statistical sample of end-use customers' load reductions for non-interval metered residential Direct Load Control customers as set forth in the PJM Manuals, pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions, or a current statistical sample of end-use customers' load reductions, and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and
- v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.

SCHEDULE 2 - COMPONENTS OF COST

(a) Each Market Participant obligated to sell energy on the PJM Interchange Energy Market at cost-based rates may include the following components or their equivalent in the determination of costs for energy supplied to or from the PJM Region:

For generating units powered by boilers

Firing-up cost

Peak-prepared-for maintenance cost

For generating units powered by machines

Starting cost from cold to synchronized operation

For all generating units

Incremental fuel cost

Incremental maintenance cost

No-load cost during period of operation

Incremental labor cost

Other incremental operating costs

For a generating unit that is subject to operational limitations due to energy or environmental limitations imposed on the generating unit by Applicable Laws and Regulations (as defined in the PJM Tariff), the Market Participant may include in the calculation of its “other incremental operating costs” an amount reflecting the unit-specific Energy Market Opportunity Costs expected to be incurred. Such unit-specific Energy Market Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the relevant compliance period, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Energy Market Opportunity Cost shall be zero. Notwithstanding the foregoing, a Market Participant may submit a request to PJM for consideration and approval of an alternative method of calculating its Energy Market Opportunity Cost if the standard methodology described herein does not accurately represent the Market Participant’s Energy Market Opportunity Cost.

For a generating unit that is subject to operational limitations because it only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, or (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure, the Market Participant may include in the calculation of its “other incremental operating costs” an amount reflecting the unit-specific Non-Regulatory Opportunity Costs expected to be incurred. Such unit-specific Non-Regulatory Opportunity Costs are calculated by forecasting Locational Marginal Prices based on future contract prices for electricity using PJM Western Hub forward prices, taking into account

historical variability and basis differentials for the bus at which the generating unit is located for the prior three year period immediately preceding the period of time in which the unit is bound by the referenced restrictions, and subtract therefrom the forecasted costs to generate energy at the bus at which the generating unit is located, as specified in more detail in PJM Manual 15. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting Non-Regulatory Opportunity Cost shall be zero.

(b) All fuel costs shall employ the marginal fuel price experienced by the Member.

(c) The PJM Board, upon consideration of the advice and recommendations of the Members Committee, shall from time to time define in detail the method of determining the costs entering into the said components, and the Members shall adhere to such definitions in the preparation of incremental costs used on the Interconnection.

SCHEDULE 2 - EXHIBIT A - EXPLANATION OF THE TREATMENT OF THE COSTS OF EMISSION ALLOWANCES

The cost of emission allowances is included in “Other Incremental Operating Costs” pursuant to Schedule 2. The replacement cost of emission allowances will be used to recover the cost of emission allowances consumed as a result of producing energy for the PJM Region.

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Consistent with definitions promulgated by the PJM Board upon consideration of the advice and recommendations of the Members Committee under Schedule 2, each Member subject to Schedule 2 will determine and provide to the Interconnection its replacement cost of emission allowances, such cost to be an amount not exceeding the market price index published by Cantor-Fitzgerald Environmental Brokerage Services (“EBS”), or a PJM Board approved index in the event that EBS should cease publication of such index. As with all other components of cost required for accounting under this Agreement, each Member subject to Schedule 2 will use the same replacement cost of emissions allowances, so determined, as it uses for coordinating operation of its generating facilities hereunder.

For each Member subject to Schedule 2, the cost of emissions allowances is included in the cost of energy supplied to or received from the PJM Region.

Payment

The Members subject to Schedule 2 waive the right of payment-in-kind for emission allowances for transactions wholly between the parties. Cash payments for emission allowances consumed in providing energy for the PJM Region shall be incorporated into and conducted pursuant to the billing procedures for energy prescribed by this Agreement.

Calculation of Emission Allowance Amount and Cost

Pursuant to the letter from the PJM Interconnection to FERC dated June 26, 1995, the calculation of an annual average for the cost of emission allowances, described below, is required due to the profile of the PJM physical system and PJM Energy Management software system. An average emission allowance cost based on a standard production cost study case will be used to calculate the average cost of emission allowances for each pool megawatt produced.

The Emission Allowances (Tons of SO₂) associated with a transaction will be calculated by multiplying the magnitude of a transaction (MWhr) by an Emissions per MWhr Factor (Tons of SO₂ per MWhr):

$$\begin{array}{rclcl} \text{Emission} & & \text{Transaction} & & \text{Emissions} \\ \text{Allowances} & = & \text{Magnitude} & \times & \text{per MWhr} \\ \text{Used} & & & & \text{Factor} \\ \text{(Tons of SO}_2\text{)} & & \text{(MWhr)} & & \text{(Tons of SO}_2\text{ per MWhr)} \end{array}$$

The Emissions per MWhr Factor will be calculated by dividing the forecast annual emissions from all Phase I units (Tons of SO₂) by the Forecast Annual Total PJM Energy Production (MWhr):

$$\begin{array}{l} \text{Emissions} \\ \text{per MWhr} \\ \text{Factor} \\ \text{(Tons of SO}_2\text{)} \\ \text{per MWhr} \end{array} = \frac{\text{Forecast Annual Phase I Unit Emissions (Tons of SO}_2\text{)}}{\text{Forecast Annual Total PJM Energy Production (MWhr)}}$$

Likewise, the cost (Dollars) of the Emission Allowances for a transaction will be calculated by multiplying the transaction magnitude (MWhr) by a Charge per MWhr Factor (Dollars per MWhr).

$$\begin{array}{l} \text{Cost of Emission} \\ \text{Allowances Used} \\ \text{(Dollars)} \end{array} = \begin{array}{l} \text{Transaction} \\ \text{Magnitude} \\ \text{(MWhr)} \end{array} \times \begin{array}{l} \text{Charge} \\ \text{per MWhr Factor} \\ \text{(Dollars per MWhr)} \end{array}$$

The Charge per MWhr Factor will be calculated by multiplying, for each Member subject to Schedule 2, its Forecast Annual Emissions (Tons of SO₂) by its respective Emissions Allowance Replacement Cost (Dollars per Ton of SO₂) to yield each the forecasted annual cost of emissions (Dollars). Then, the total of forecasted annual cost of emissions for each Member subject to Schedule 2 is divided by the Forecast Annual Total PJM Energy Production (MWhr) to determine the Charge per MWhr Factor (Dollars per MWhr).

$$\begin{array}{l} \text{Charge per} \\ \text{MWhr Factor} \end{array} = \frac{\Sigma(A \times B)}{C}, \text{ where:}$$

A = Member's Forecasted Annual Emissions, (Tons of SO₂)

B = Emission Allowance Replacement Cost, (Dollars per Ton of SO₂, per company)

C = Forecast Annual PJM Energy Production, (MWhr)

**SCHEDULE 3 -
ALLOCATION OF THE COST AND EXPENSES
OF THE OFFICE OF THE INTERCONNECTION**

(a) Each group of Affiliates, each group of Related Parties, and each Member that is not in such a group shall pay an annual membership fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee as of the Effective Date shall be \$5,000. The annual membership fee shall be charged on a calendar year basis. In the year that a new membership commences, the annual membership fee may be reduced, at the election of the entity joining, by 1/12th for each full month that has passed prior to membership commencing. If the entity seeking to join elects to pay a prorated annual membership fee as provided here, it shall not be permitted to vote at meetings until the first day following the date that its entry as a new Member is announced at a Members Committee meeting, provided that if an entity's membership is terminated and it seeks to rejoin within twelve months, it will be subject to the full \$5,000 annual membership fee. Annual membership fees shall not be refunded, in whole or in part, upon termination of membership. Each group of Affiliates, each group of Related Parties, and each Member that does not timely pay its annual membership fee by January 1 shall be deemed to have given notice of its intent to withdrawal from PJM Membership in accordance with Section 18.18.2 of this Agreement. PJM shall provide the affected group of Affiliates, group of Related Parties and/or Member with notification (electronic or otherwise) of its intent to apply this provision and the affected group of Affiliates, group of Related Parties and/or Member shall have 90 days therefrom to make payment of its annual membership fee before its withdrawal from PJM Membership becomes effective.

(b) Each group of State Offices of Consumer Advocates from the same state or the District of Columbia and each State Consumer Advocate that nominates its representative to vote on the Members Committee but is not in such a group shall pay an annual fee, the proceeds of which shall be used to defray the costs and expenses of the LLC, including the Office of the Interconnection. The amount of the annual fee shall be \$500. The annual membership fee shall be charged on a calendar year basis and shall not be subject to proration for memberships commencing during a calendar year.

(c) The amount of the annual fees provided for herein shall be adjusted from time to time by the PJM Board to keep pace with inflation.

(d) All remaining costs of the operation of the LLC and the Office of the Interconnection and the expenses, including, without limitation, the costs of any insurance and any claims not covered by insurance, associated therewith as provided in this Agreement shall be costs of PJM Interconnection, L.L.C. Administrative Services and shall be recovered as set forth in Schedule 9 to the PJM Tariff. Such costs may include costs associated with debt service, including the costs of funding reserve accounts or meeting coverage or similar requirements that financing covenants may necessitate.

(e) An entity accepted for membership in the LLC shall pay all costs and expenses associated with additions and modifications to its own metering, communication, computer, and

other appropriate facilities and procedures needed to effect the inclusion of the entity in the operation of the Interconnection, and for additional services requested by Members from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection.

**SCHEDULE 4 -
STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE LLC**

Any entity which wishes to become a Member of the LLC shall, pursuant to Section 11.6 of this Agreement, tender to the President an application, upon the acceptance of which it shall execute a supplement to this Agreement in the following form:

Additional Member Agreement

1. This Additional Member Agreement (the "Supplemental Agreement"), dated as of _____, is entered into among _____ and the President of the LLC acting on behalf of its Members.
2. _____ has demonstrated that it meets all of the qualifications required of a Member to the Operating Agreement. If expansion of the PJM Region is required to integrate _____'s facilities, a copy of Attachment J from the PJM Tariff marked to show changes in the PJM Region boundaries is attached hereto. _____ agrees to pay for all required metering, telemetering and hardware and software appropriate for it to become a member.
3. _____ agrees to be bound by and accepts all the terms of the Operating Agreement as of the above date.
4. _____ hereby gives notice that the name and address of its initial representative to the Members Committee under the Operating Agreement shall be: _____
5. The President of the LLC is authorized under the Operating Agreement to execute this Supplemental Agreement on behalf of the Members.
6. The Operating Agreement is hereby amended to include _____ as a Member of the LLC thereto, effective as of _____, _____, the date the President of the LLC countersigned this Agreement.

IN WITNESS WHEREOF, _____ and the Members of the LLC have caused this Supplemental Agreement to be executed by their duly authorized representatives.

Members of the LLC

By: _____
Name: _____
Title: President

By: _____
Name: _____
Title: _____

**SCHEDULE 5 -
PJM DISPUTE RESOLUTION PROCEDURES**

References to section numbers in this Schedule 5 refer to sections of this Schedule 5, unless otherwise specified.

1. DEFINITIONS

1.1 Alternate Dispute Resolution Coordinator.

“Alternate Dispute Resolution Coordinator” shall mean the individual designated by the Office of the Interconnection.

1.2 Related PJM Agreements.

“Related PJM Agreements” shall mean this Agreement, the Consolidated Transmission Owners Agreement and the Reliability Assurance Agreement.

2. PURPOSES AND OBJECTIVES

2.1 Common and Uniform Procedures.

The PJM Dispute Resolution Procedures are intended to establish common and uniform procedures for resolving disputes arising under the Related PJM Agreements. To the extent any of the foregoing agreements or the PJM Tariff contains dispute resolution provisions expressly applicable to disputes arising thereunder, however, this Agreement shall not supplant such provisions, which shall apply according to their terms.

2.2 Interpretation.

To the extent permitted by applicable law, the PJM Dispute Resolution Procedures are to be interpreted to effectuate the objectives set forth in Section 2.1. To the extent permitted by these PJM Dispute Resolution Procedures, the Alternate Dispute Resolution Coordinator shall coordinate with the established dispute resolution committee of an Applicable Regional Entity, where appropriate, in order to conserve administrative resources and to avoid duplication of dispute resolution staffing.

3. NEGOTIATION AND MEDIATION

3.1 When Required.

The parties to a dispute shall undertake good-faith negotiations to resolve any dispute as to a matter governed by one of the Related PJM Agreements. Each party to a dispute shall designate an executive with authority to resolve the matter in dispute to participate in such negotiations. Any dispute as to a matter governed by one of the Related PJM Agreements that has not been resolved through good-faith negotiation shall be subject to non-binding mediation prior to the initiation of arbitral, regulatory, judicial, or other dispute resolution proceedings as may be appropriate as provided by these PJM Dispute Resolution Procedures.

3.2 Procedures.

3.2.1 Initiation.

If a dispute that is subject to the mediation procedures specified herein has not been resolved through good-faith negotiation, a party to the dispute shall notify the Alternate Dispute Resolution Coordinator in writing of the existence and nature of the dispute prior to commencing any other form of proceeding for resolution of the dispute. The Alternate Dispute Resolution Coordinator shall have ten calendar days from the date it first receives notification of the existence of a dispute from any of the parties to the dispute in which to distribute to the parties a list of mediators.

3.2.2 Selection of Mediator.

The Alternate Dispute Resolution Coordinator shall distribute to the parties by facsimile or other electronic means a list containing the names of seven mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as it shall deem appropriate to the dispute. The Alternate Dispute Resolution Coordinator may draw from the lists of mediators maintained by the established dispute resolution committee of an Applicable Regional Entity, as the Alternate Dispute Resolution Coordinator shall deem appropriate. In the event the Office of the Interconnection is one of the parties to the dispute, the Alternate Dispute Resolution Coordinator shall distribute the names of all qualified mediators on the Alternate Dispute Resolution Coordinator's list. The persons on the proposed list of mediators shall have no official, financial, or personal conflict of interest with respect to the issues in controversy, unless the interest is fully disclosed in writing to all participants in the mediation process and all such participants waive in writing any objection to the interest. The parties shall then alternate in striking names from the list with the last name on the list becoming the mediator. The determination of which party shall have the first strike off the list shall be determined by lot. The parties shall have ten calendar days to complete the mediator selection process, unless the time is extended by mutual agreement.

3.2.3 Advisory Mediator.

If the Alternate Dispute Resolution Coordinator deems it appropriate, it shall distribute two lists, one containing the names of seven mediators with mediation experience (or a list containing the names of all current mediators in the event of a dispute involving the Office of the Interconnection), and one containing the names of seven mediators with technical or business experience in the electric power industry. In connection with circulating the foregoing lists, the Alternate Dispute Resolution Coordinator shall specify one of the lists as containing the proposed mediators, and the other as a list of proposed advisors to assist the mediator in resolving the dispute. The parties shall then utilize the alternative strike procedure set forth above until one name remains on each list, with the last named persons serving as the mediator and advisor.

3.2.4 Mediation Process.

The disputing parties shall attempt in good faith to resolve their dispute in accordance with procedures and a timetable established by the mediator. In furtherance of the mediation efforts, the mediator may:

- (a) Require the parties to meet for face-to-face discussions, with or without the mediator;
- (b) Act as an intermediary between the disputing parties;
- (c) Require the disputing parties to submit written statements of issues and positions;
- (d) If requested by the disputing parties at any time in the mediation process, provide a written recommendation on resolution of the dispute including, if requested, the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties; and
- (e) Adopt, when appropriate, the Center for Public Resources Model ADR Procedures for the Mediation of Business Disputes (as revised from time to time) to the extent such Procedures are not inconsistent with any rule, standard, or procedure adopted by the Office of the Interconnection or with any provision of this Agreement.

3.2.5 Mediator's Assessment.

- (a) If a resolution of the dispute is not reached by the thirtieth day after the appointment of the mediator or such later date as may be agreed to by the parties, if not previously requested to do so the mediator shall promptly provide the disputing parties with a written, confidential, non-binding recommendation on resolution of the dispute, including the assessment by the mediator of the merits of the principal positions being advanced by each of the disputing parties. The recommendation may incorporate or append, if and as the mediator may deem appropriate, any recommendations or any assessment of the positions of the parties by the advisor, if any. Upon request, the mediator shall provide any additional recommendations or assessments the mediator shall deem appropriate.
- (b) At a time and place specified by the mediator after delivery of the foregoing recommendation, the disputing parties shall meet in a good faith attempt to resolve the dispute in light of the recommendation of the mediator. Each disputing party shall be represented at the meeting by a person with authority to settle the dispute, along with such other persons as each disputing party shall deem appropriate. If the disputing parties are unable to resolve the dispute at or in connection with this meeting, then: (i) any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate as provided in the PJM Dispute Resolution Procedures; and (ii) the recommendation of the mediator, and any statements made by any party in the mediation process, shall have no further force or effect, and shall not be admissible for any purpose, in any subsequent arbitral, administrative, judicial, or other proceeding.

3.3 Costs.

Except as specified in Section 4.13, the costs of the time, expenses, and other charges of the mediator and any advisor, and of the mediation process, shall be borne by the parties to the dispute, with each side in a mediated matter bearing one-half of such costs, and each party bearing its own costs and attorney's fees incurred in connection with the mediation.

4. ARBITRATION

4.1 When Required.

Any dispute as to a matter: (i) governed by one of the Related PJM Agreements that has not been resolved through the mediation procedures specified herein, (ii) involving a claim that one or more of the parties owes or is owed a sum of money, and (iii) the amount in controversy is less than \$1,000,000.00, shall be subject to binding arbitration in accordance with the procedures specified herein. If the parties so agree, any other disputes as to a matter governed by a Related PJM Agreement may be submitted to binding arbitration in accordance with the procedures specified herein.

4.2 Binding Decision.

Except as specified in Section 4.1, the resolution by arbitration of any dispute under this Agreement shall not be binding.

4.3 Initiation.

A party or parties to a dispute which is subject to the arbitration procedures specified herein shall send a written demand for arbitration to the Alternate Dispute Resolution Coordinator with a copy to the other party or parties to the dispute. The demand for arbitration shall state each claim for which arbitration is being demanded, the relief being sought, a brief summary of the grounds for such relief and the basis for the claim, and shall identify all other parties to the dispute.

4.4 Selection of Arbitrator(s).

The parties to a dispute for which arbitration has been demanded may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of arbitrators prepared for the dispute by the Alternate Dispute Resolution Coordinator and delivered to the parties by facsimile or other electronic means promptly after receipt by the Alternate Dispute Resolution Coordinator of a demand for arbitration. The Alternate Dispute Resolution Coordinator may draw from the lists of arbitrators maintained by the established dispute resolution committee of an Applicable Regional Entity, as the Alternate Dispute Resolution Coordinator deems appropriate. In the event the Office of the Interconnection is one of the parties to the dispute, the Alternate Dispute Resolution Coordinator shall distribute the names of all qualified arbitrators on the Alternate Dispute Resolution Coordinator's list. If the parties are unable to agree on a single arbitrator by the fourteenth day following delivery of the foregoing list of arbitrators or such other date as agreed to by the parties, then not later than the end of the seventh business day thereafter the party or parties demanding arbitration on the one hand, and the party or parties responding to the demand for arbitration on the other, shall each designate an arbitrator from a list for the dispute prepared by the Alternate Dispute Resolution Coordinator. The arbitrators so chosen shall then choose a third arbitrator.

4.5 Procedures.

The Alternate Dispute Resolution Coordinator shall compile and make available to the arbitrator(s) and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified in these PJM Dispute Resolution Procedures, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator(s) deem appropriate. To the extent deemed appropriate by the Alternate Dispute Resolution Coordinator, the procedures shall be based on the American Arbitration Association Rules, to the extent such Rules are not inconsistent with any rule, standard or procedure adopted by the Office of the Interconnection, or with any provision of these PJM Dispute Resolution Procedures. Upon selection of the arbitrator(s), arbitration shall go forward in accordance with applicable procedures.

4.6 Summary Disposition and Interim Measures.

4.6.1 Lack of Good Faith Basis.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator(s) does not have a good faith basis in either law or fact. If the arbitrator(s) determine(s) that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator(s) shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator(s) to the prevailing party.

4.6.2 Discovery Limits.

The procedures for the arbitration of a dispute shall provide a means for summary disposition without discovery of facts if there is no dispute as to any material fact, or with such limited discovery as the arbitrator(s) shall determine is reasonably likely to lead to the prompt resolution of any disputed issue of material fact.

4.6.3 Interim Decision.

The procedures for the arbitration of a dispute shall permit any party to a dispute to request the arbitrator(s) to render a written interim decision requiring that any action or decision that is the subject of a dispute not be put into effect, or imposing such other interim measures as the arbitrator(s) deem necessary or appropriate, to preserve the rights and obligations secured by any of the Related PJM Agreements during the pendency of the arbitration proceeding. The parties shall be bound by such written decision pending the outcome of the arbitration proceeding.

4.7 Discovery of Facts.

4.7.1 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, and (iii) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified by the procedures established by the arbitrator(s) or agreement of the parties.

4.7.2 Procedures Arbitrator.

The sole arbitrator, or the arbitrator selected by the arbitrators chosen by the parties, as the case may be (such arbitrator being hereafter referred to as the "Procedures Arbitrator"), shall be responsible for establishing the timing, amount, and means of discovery, and for resolving discovery and other pre-hearing disagreement. If a dispute involves contested issues of fact, promptly after the selection of the arbitrator(s) the Procedures Arbitrator shall convene a meeting of the parties for the purpose of establishing a schedule and plan of discovery and other pre-hearing actions.

4.8 Evidentiary Hearing.

The procedures for the arbitration of a dispute shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be as described in the Federal Rules of Evidence, except as modified by the procedures established by the arbitrator(s) or agreement of the parties. The arbitrator(s) may require such written or other submissions from the parties as shall be deemed appropriate, including submission of the direct testimony of witnesses in written form. The arbitrator(s) may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. Any party or parties may arrange for the preparation of a record of the hearing, and shall pay the costs thereof. Such party or parties shall have no obligation to provide or agree to the provision of a copy of the record of the hearing to any party that does not pay an equal share of the cost of the record. At the request of any party, the arbitrator(s) shall determine a fair and equitable allocation of the costs of the preparation of a record between or among the parties to the proceeding willing to share such costs.

4.9 Confidentiality.

4.9.1 Designation.

Any document or other information obtained in the course of an arbitral proceeding and not otherwise available to the receiving party, including any such information contained in documents or other means of recording information created during the course of the proceeding, may be designated "Confidential" by the producing party. The party producing documents or other information marked "Confidential" shall have twenty days from the production of such material to submit a request to the Procedures Arbitrator to establish such requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information and the rights of the parties, which requirements shall be binding on all parties to the dispute. Prior to the decision of the Procedures Arbitrator on a request for confidential treatment, documents or other information designated as "Confidential" shall not be used by the receiving party or parties, or the arbitrator(s), or anyone working for or on behalf of any of the foregoing, for any purpose other than the arbitration proceeding, and shall not be disclosed in any form to any person not involved in the arbitration proceeding without the prior written consent of the party producing the information or as permitted by the Procedures Arbitrator.

4.9.2 Compulsory Disclosure.

Any party receiving a request or demand for disclosure, whether by compulsory process, discovery request, or otherwise, of documents or information obtained in the course of an arbitration proceeding that have been designated "Confidential" and that are subject to a non-disclosure requirement under these PJM Dispute Resolution Procedures or a decision of the Procedures Arbitrator, shall immediately inform the party from which the information was obtained, and shall take all reasonable steps, short of incurring sanctions or other penalties, to afford the person or entity from which the information was obtained an opportunity to protect the information from disclosure. Any party disclosing information in violation of these PJM Dispute Resolution Procedures or requirements established by the Procedures Arbitrator shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

4.9.3 Public Information.

Nothing in the Related PJM Agreements shall preclude the use of documents or information properly obtained outside of an arbitral proceeding, or otherwise public, for any legitimate purpose, notwithstanding that the information was also obtained in the course of the arbitral proceeding.

4.10 Timetable.

Promptly after the selection of the arbitrator(s), the arbitrator(s) shall set a date for the issuance of the arbitral decision, which shall be not later than eight months (or such earlier date as may be agreed to by the parties to the dispute) from the date of the selection of the arbitrator(s), with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed absent extraordinary circumstances. The arbitrator(s) shall have the power to impose sanctions, including dismissal of the proceeding for dilatory tactics or undue delay in completing the arbitral proceedings.

4.11 Advisory Interpretations.

Except as to matters subject to decision in the arbitration proceeding, the arbitrator(s) may request as may be appropriate from any committee or subcommittee established under a Related PJM Agreement or by the Office of the Interconnection, an interpretation of any Related PJM Agreements, or of any standard, requirement, procedure, tariff, Schedule, principle, plan or other criterion or policy established by any committee or subcommittee. Except to the extent that the Office of the Interconnection is itself a party to a dispute, the arbitrator(s) may request the advice of the Office of the Interconnection with respect to any matter relating to a responsibility of the Office of the Interconnection under the Agreement or with respect to any of the Related PJM Agreements, or to the PJM Manuals. Any such interpretation or advice shall not relieve the arbitrator(s) of responsibility for resolving the dispute or deciding the arbitration proceeding in accordance with the standards specified herein.

4.12 Decisions.

The arbitrator(s) shall issue a written decision, including findings of fact and the legal basis for the decision. The arbitral decision shall be based on (i) the evidence in the record, (ii) the terms of the Related PJM Agreements, as applicable, (iii) applicable United States federal and state law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) relevant decisions in previous arbitration proceedings. The arbitrator(s) shall have no authority to revise or alter any provision of the Related PJM Agreements. Any arbitral decision issued pursuant to these PJM Dispute Resolution Procedures that affects matters subject to the jurisdiction of FERC under Section 205 of the Federal Power Act shall be filed with FERC.

4.13 Costs.

Unless the arbitrator(s) shall decide otherwise, the costs of the time, expenses, and other charges of the arbitrator(s) shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitral proceeding shall bear its own costs and fees. The arbitrator(s) may award all or a portion of the costs of the time, expenses, and other charges of the arbitrator(s), the costs of arbitration, attorney's fees, and the costs of mediation, if any, to any party that substantially prevails on an issue determined by the arbitrator(s) to have been raised without a substantial basis.

4.14 Enforcement.

If the decision of the arbitrator(s) is binding, the judgment may be entered on such arbitral award by any court having jurisdiction thereof; provided, however, that within one year of the issuance of the arbitral decision any party affected thereby may request FERC or any other federal, state, regulatory or judicial authority having jurisdiction to vacate, modify, or take such other action as may be appropriate with respect to any arbitral decision that is based upon an error of law, or is contrary to the statutes, rules, or regulations administered or applied by such authority. Any party making or responding to, or intervening in proceedings resulting from, any such request, shall request the authority to adopt the resolution, if not clearly erroneous, of any issue of fact expressly or necessarily decided in the arbitral proceeding, whether or not the party participated in the arbitral proceeding.

5. ALTERNATE DISPUTE RESOLUTION COORDINATOR

5.1 Responsibilities.

The duties of the Alternate Dispute Resolution Coordinator shall include the following:

- i) Maintain a list of persons qualified by temperament and experience, and with technical or legal expertise in matters likely to be the subject of disputes, to serve as mediators or arbitrators under these PJM Dispute Resolution Procedures, which lists shall be updated no less than annually and shall include the names of any mediators or arbitrators recommended by any Member; and
- ii) Provide to disputing parties lists of mediators, advisors or arbitrators to resolve particular disputes.

**SCHEDULE 6 -
REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL**

References to section numbers in this Schedule 6 refer to sections of this Schedule 6, unless otherwise specified.

1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1.1 Purpose and Objectives.

This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan (also referred to as “RTEP”) to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.

1.2 Conformity with NERC *Reliability Standards* and Other Applicable Reliability Criteria.

- (a) NERC establishes Reliability Standards to promote the reliability, adequacy and security of the North American bulk power supply as related to the operation and planning of electric systems.
- (b) ReliabilityFirst Corporation is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the geographic region described in the applicable agreements between NERC and ReliabilityFirst Corporation, as approved by the FERC, through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the ReliabilityFirst Corporation.
- (c) [Reserved]
- (c.01) [Reserved]
- (c.02) SERC is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the VACAR subregion of SERC. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System for SERC.
- (d) The Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals.
- (e) The Regional Transmission Expansion Plan planning criteria shall include, Office of the Interconnection planning procedures, NERC Reliability Standards, Regional Entity reliability principles and standards, and the individual Transmission Owner FERC filed planning criteria as filed in FERC Form No. 715, and posted on the PJM website. FERC Form No. 715 material will be posted to the PJM website, subject to applicable Critical Energy Infrastructure Information (CEII) requirements.
- (f) The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan.

1.3 Establishment of Committees.

(a) The Planning Committee shall be open to participation by (i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates; and (v) any other interested entities or persons and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions. The Transmission Owners shall supply representatives to the Planning Committee, and other Members may provide representatives as they deem appropriate, to provide the data, information, and support necessary for the Office of the Interconnection to perform studies as required and to develop the Regional Transmission Expansion Plan.

(b) The Transmission Expansion Advisory Committee established by the Office of the Interconnection will meet periodically with representatives of the Office of the Interconnection to provide advice and recommendations to the Office of the Interconnection to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee participants shall be given an opportunity to provide advice and recommendations for consideration by the Office of the Interconnection regarding sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives in the studies and analyses to be conducted by the Office of the Interconnection. The Transmission Expansion Advisory Committee participants shall be given the opportunity to review and provide advice and recommendations on the projects to be included in the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee meetings shall include discussions addressing interregional planning issues, as required. The Transmission Expansion Advisory Committee shall be open to participation by: (i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates; and (v) any other interested entities or persons. The Transmission Expansion Advisory Committee shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional Planning Process Manual (PJM Manual M-14 series) and by the rules and procedures applicable to PJM committees.

(c) The Subregional RTEP Committees established by the Office of the Interconnection shall facilitate the development and review of the Subregional RTEP Projects. The Subregional RTEP Committees will be responsible for the initial review of the Subregional RTEP Projects, and to provide recommendations to the Transmission Expansion Advisory Committee concerning the Subregional RTEP Projects. A Subregional RTEP Committee may of its own accord or at the request of a Subregional RTEP Committee participant, also refer specific Subregional RTEP Projects to the

Transmission Expansion Advisory Committee for further review, advice and recommendations.

(d) The Subregional RTEP Committees shall be responsible for the timely review of the criteria, assumptions and models used to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements, proposed solutions prior to finalizing the Local Plan, the coordination and integration of the Local Plans into the RTEP, and addressing any stakeholder issues unresolved in the Local Plan process. The Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the criteria, assumptions, and models used in local planning activities prior to finalizing the Local Plan. The Subregional RTEP Committees meetings shall include discussions addressing interregional planning issues, as required. Once finalized, the Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the Local Plans as integrated into the RTEP, prior to the submittal of the final Regional Transmission Expansion Plan to the PJM Board for approval. In addition, the Subregional RTEP Committees will provide sufficient opportunity to review and provide written comments to the Transmission Owners on any Supplemental Projects included in the Local Plan.

(e) The Subregional RTEP Committees shall be open to participation by: (i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates and (v) any other interested entities or persons.

(f) Each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions and models to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements. Each Subregional RTEP Committee shall schedule and facilitate an additional Subregional RTEP Committee meeting, per planning cycle, and as required to review the identified criteria violations and potential solutions. The Subregional RTEP Committees may facilitate additional meetings to incorporate more localized areas in the subregional planning process. At the discretion of the Office of the Interconnection, a designated Transmission Owner may facilitate Subregional RTEP Committee meeting(s), or the additional meetings incorporating the more localized areas.

(g) The Subregional RTEP Committees shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional Planning Process Manual (Manual M-14 series) and by the rules and procedures applicable to PJM committees.

1.4 Contents of the Regional Transmission Expansion Plan.

- (a) The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering federal and state Public Policy Requirements.
- (b) The Regional Transmission Expansion Plan shall reflect, consistent with the requirements of this Schedule 6, transmission enhancements and expansions; load forecasts; and capacity forecasts, including expected generation additions and retirements, demand response, and reductions in demand from energy efficiency and price responsive demand for at least the ensuing ten years.
- (c) The Regional Transmission Expansion Plan shall, at a minimum, include a designation of the Transmission Owner(s) or other entity(ies) that will construct, own, maintain, operate, and/or finance each transmission enhancement and expansion and how all reasonably incurred costs are to be recovered.
- (d) The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take into account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region; (v) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; and (vi) strive for consistency in planning data and assumptions that may relieve transmission congestion across multiple regions.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if: (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the Transmission System or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection in its on-going evaluation of the Transmission System's market efficiency and operational performance; (iii) required as a result of the Office of the Interconnection's assessment of the Transmission System's compliance with NERC Reliability Standards, more stringent reliability criteria, if any, or PJM planning and operating criteria; (iv) required to address constraints or available transfer capability shortages, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement, constraints or shortages as a result of expected generation retirements, constraints or shortages based on an evaluation of load forecasts, or system reliability needs arising from proposals for the addition of Transmission Facilities in the PJM Region; or (v) expansion of the Transmission System is proposed by one or more Transmission Owners, Interconnection Customers, Network Service Users or Transmission Customers, or any party that funds Network Upgrades pursuant to Section 7.8 of Schedule 1 of this Agreement. The Office of the Interconnection may initiate the enhancement and expansion study process to address or consider, where appropriate, requirements or needs arising from sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives.

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee participants of, as well as publicly notice, the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee participants shall notify the Office of the Interconnection in writing of any additional transmission considerations they would like to have included in the Office of the Interconnection's analyses.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

In conducting the enhancement and expansion studies, the Office of the Interconnection shall not limit its analyses to bright line tests to identify and evaluate potential Transmission System limitations, violations of planning criteria, or transmission needs. In addition to the bright line tests, the Office of the Interconnection shall employ sensitivity studies, modeling assumption variations, and scenario analyses, and shall also consider Public Policy Objectives in the studies and analyses, so as to mitigate the possibility that bright line metrics may inappropriately include

or exclude transmission projects from the transmission plan. Sensitivity studies, modeling assumption variations, and scenario analyses shall take account of potential changes in expected future system conditions, including, but not limited to, load levels, transfer levels, fuel costs, the level and type of generation, generation patterns (including, but not limited to, the effects of assumptions regarding generation that is at risk for retirement and new generation to satisfy Public Policy Objectives), demand response, and uncertainties arising from estimated times to construct transmission upgrades. The Office of the Interconnection shall use the sensitivity studies, modeling assumption variations and scenario analyses in evaluating and choosing among alternative solutions to reliability, market efficiency and operational performance needs. The Office of the Interconnection shall provide the results of its studies and analyses to the Transmission Expansion Advisory Committee to consider the impact that sensitivities, assumptions, and scenarios may have on Transmission System needs and the need for transmission enhancements or expansions. Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

- (a) An identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.
- (b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.
- (c) Identification, evaluation and analysis of potential transmission expansions and enhancements, demand response programs, and other alternative technologies as appropriate to maintain system reliability.
- (d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition, market efficiency, operational performance, and Public Policy Requirements in the PJM Region.
- (e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to Section 7.8 of Schedule 1 of this Agreement.
- (f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.
- (g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and market efficiency.
- (h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure that the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement. Enhancements and expansions related to stage 1A Auction

Revenue Rights identified pursuant to this Section shall be recommended for inclusion in the Regional Transmission Expansion Plan together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Section 1.5.3(h) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to Section 1.5.6(l) of Schedule 6 of this Agreement and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current Local Plan; and (v) all criteria, assumptions and models used in the current Local Plan. The data required under this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region, Independent State Agencies Committee, and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study, including information regarding potential sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives that may be considered.

(d) The Office of the Interconnection shall supply to the Transmission Expansion Advisory Committee and the Subregional RTEP Committees reasonably required information and data utilized to develop the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions and Office of the Interconnection's CEII process.

(e) The Office of the Interconnection shall provide access through the PJM website, to the Transmission Owner's Local Plan, including all criteria, assumptions and models used by the

Transmission Owners in developing their respective Local Plan (“Local Plan Information”). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in Section 18.17 of this Operating Agreement; (2) the Office of the Interconnection’s CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, the Office of the Interconnection may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in Section 18.17 of this Operating Agreement and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM Interconnection, L.L.C., the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the Transmission Expansion Advisory Committee, and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the Transmission Systems of the surrounding Regional Entities and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements:

- Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C., which is found at <http://www.pjm.com/~media/documents/agreements/joa-complete.ashx>;
- Northeastern ISO/RTO Planning Coordination Protocol, which is described at Schedule 6-B and found at <http://www.pjm.com/~media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>;
- Joint Operating Agreement Among and Between New York Independent System Operator Inc., which is found at <http://www.pjm.com/~media/documents/agreements/nyiso-pjm.ashx>;
- Interregional Transmission Coordination Between the SERTP and PJM Regions, which is found at Schedule 6-A of this Agreement;
- Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions, which is located at Schedule 12-B of the PJM Open Access Transmission Tariff;
- Joint Reliability Coordination Agreement Between the Midwest Independent System Operator, Inc.; PJM Interconnection, L.L.C. and Progress Energy Carolinas.

- (i) Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.
- (ii) An entity, including existing Transmission Owners and Nonincumbent Developers, may submit potential Interregional Transmission Projects pursuant to Section 1.5.8 of this Schedule 6.
- (c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.
- (d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

- (a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies, including sensitivity studies and scenario analyses on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committees.
- (b) The Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the Regional Transmission Expansion Plan process. The purpose of the assumptions meeting shall be to provide an open forum to discuss the following: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) Public Policy Requirements identified by the states for consideration in the Office of the Interconnection's transmission planning analyses; (iii) Public Policy Objectives identified by stakeholders for consideration in the Office of the Interconnection's transmission planning analyses; (iii) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, price responsive demand, generating additions and retirements, market efficiency and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by the Committee participants. Prior to the initial assumptions meeting, Committee participants will be afforded the opportunity to provide input and submit suggestions regarding the information identified in items (i) through (iv) of this subsection. Following the assumptions meeting and prior to performing the evaluation and analyses, the Office of the Interconnection shall determine the range of assumptions to be used in the studies and scenario analyses, based on the advice and recommendations of the Transmission Expansion Advisory Committee and

Subregional RTEP Committees and the validation of Public Policy Requirements and assessment and prioritization of Public Policy Objectives by the states through the Independent State Agencies Committee. The Office of the Interconnection shall document and publicly post its determination for review. Such posting shall include an explanation of those Public Policy Requirements and Public Policy Objectives adopted at the assumptions stage to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission System and an explanation of why other Public Policy Requirements and Public Policy Objectives introduced by stakeholders at the assumptions stage were not adopted.

(c) After the assumptions meeting(s), the Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants (as defined in Sections 1.3(b) and 1.3(c) of this Schedule 6) to review and evaluate the following arising from the studies performed by the Office of the Interconnection, including sensitivity studies and scenario analyses: (i) any identified violations of reliability criteria and analyses of the market efficiency and operational performance of the Transmission System; (ii) potential transmission solutions, including any acceleration, deceleration or modifications of a potential expansion or enhancement based on the results of sensitivities studies and scenario analyses; and (iii) the proposed Regional Transmission Expansion Plan. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the Regional Transmission Expansion Plan at these meetings or at the regularly scheduled meetings of the Planning Committee.

(d) In addition, the Office of the Interconnection shall facilitate periodic meetings with the Independent State Agencies Committee to discuss: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) regulatory initiatives, as appropriate, including state regulatory agency initiated programs, and other Public Policy Objectives, to consider including in the Office of the Interconnection's transmission planning analyses; (iii) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, generating capacity, market efficiency and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by Independent State Agencies Committee. At such meetings, the Office of the Interconnection also shall discuss the current status of the enhancement and expansion study process. The Independent State Agencies Committee may request that the Office of Interconnection schedule additional meetings as necessary. The Office of the Interconnection shall inform the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, of the input of the Independent State Agencies Committee and shall consider such input in developing the range of assumptions to be used in the studies and scenario analyses described in Section (b), above.

(e) Upon completion of its studies and analysis, including sensitivity studies and scenario analyses the Office of the Interconnection shall post on the PJM website the violations, system conditions, economic constraints, and Public Policy Requirements as detailed in Section 1.5.8(b) of this Schedule 6 to afford entities an opportunity to submit proposed enhancements or

expansions to address the posted violations, system conditions, economic constraints and Public Policy Requirements as provided for in Section 1.5.8(c) of this Schedule 6. Following the close of a proposal window, the Office of the Interconnection shall: (i) post all proposals submitted pursuant to Section 1.5.8(c) of this Schedule 6; (ii) consider proposals submitted during the proposal windows consistent with Section 1.5.8(d) of this Schedule 6 and develop a recommended plan. Following review by the Transmission Expansion Advisory Committee of proposals, the Office of the Interconnection, based on identified needs and the timing of such needs, and taking into account the sensitivity studies, modeling assumption variations and scenario analyses considered pursuant to Section 1.5.3 of this Schedule 6, shall determine, which more efficient or cost-effective enhancements and expansions shall be included in the recommended plan, including solutions identified as a result of the sensitivity studies, modeling assumption variations, and scenario analyses, that may accelerate, decelerate or modify a potential reliability, market efficiency or operational performance expansion or enhancement identified as a result of the sensitivity studies, modeling assumption variations and scenario analyses, shall be included in the recommended plan. The Office of the Interconnection shall post the proposed recommended plan for review and comment by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection before submitting the recommended plan to the PJM Board for approval.

(f) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committees.

(g) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(h) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in Sections 1.5.7 and 1.5.8 of this Schedule 6.

(i) The recommended plan shall identify enhancements and expansions proposed by a state or states pursuant to Section 1.5.9 of this Schedule 6.

(j) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to Section 1.1, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of Parts IV and VI of the PJM Tariff; (2) the proposed enhancement or expansion is consistent with

applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by Parts IV and VI of the PJM Tariff with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(k) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of Section 7.8 of Schedule 1 of this Agreement, or to facilitate upgrades pursuant to Parts II, III, or VI of the PJM Tariff, and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. Any designation under this paragraph of one or more entities to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of partial responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(l) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B) subject to FERC review and approval, shall be incorporated in any amendment to Schedule 12 of the PJM Tariff that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under Sections 1.5.6(h) and 1.5.7 of this Schedule 6, (C) the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7 of Schedule 1 of this

Agreement shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under Section (b) of Schedule 12 of the PJM Tariff for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in Section 15 of Attachment DD of OATT shall (1) be allocated across Zones based on each Zone's pro rata share of load in such LDA and (2) within each Zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(m) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, market efficiency or operational performance, pursuant to a determination by the Office of the Interconnection. These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

1.5.7 Development of Economic-based Enhancements or Expansions.

(a) Each year the Transmission Expansion Advisory Committee shall review and comment on the assumptions to be used in performing the market efficiency analysis to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each year, each Transmission Owner

will be requested to provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment. Following review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection shall submit the assumptions to be used in performing the market efficiency analysis described in this Section 1.5.7 to the PJM Board for consideration.

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability-based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in section 7.4.2(c) of Schedule 1 of this Agreement; or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items 1.5.7(b)(i-iii) is described in the PJM Manuals.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan, which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional Economic-based Enhancements or Expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, pursuant to Section 1.5.8(c) of this Schedule 6, any market participant may submit to the Office of the Interconnection a proposal to construct an additional Economic-based Enhancement or Expansion to relieve an economic constraint. Upon completion of its evaluation, including consideration of any eligible

market participant proposed Economic-based Enhancements or Expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of new Economic-based Enhancements or Expansions for review and comment. Upon consideration and advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new Economic-based Enhancements or Expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional Economic-based Enhancements or Expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional Economic-based Enhancements or Expansions pursuant to Section 1.5.6(l) of this Schedule 6. In the event the entity or entities designated as responsible for construction, owning or financing a designated new Economic-based Enhancement or Expansion declines to construct, own or finance the new Economic-based Enhancement or Expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with Sections 1.6 and 1.7 of this Schedule 6. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional Economic-based Enhancements or Expansions and whether such Economic-based Enhancements or Expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional Economic-based Enhancements or Expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this Section 1.5.7(d). An Economic-based Enhancement or Expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the Economic-based Enhancement or Expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to Section (b)(i) of Schedule 12 of the PJM Tariff the Energy Market Benefit is as follows:

$$\text{Energy Market Benefit} = [.50] * [\text{Change in Total Energy Production Cost}] + [.50] * [\text{Change in Load Energy Payment}]$$

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to Section (b)(v) of Schedule 12 of the PJM Tariff the Energy Market Benefit is as follows:

$$\text{Energy Market Benefit} = [1] * [\text{Change in Load Energy Payment}]$$

and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the Economic-based Enhancement or Expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the Economic-based Enhancement or Expansion]. The change in costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured, if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)] – [the change in value of transmission rights for each Zone with the Economic-based Enhancement or Expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion)]. The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.

And

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to Section (b)(i) of Schedule 12 of the PJM Tariff the Reliability Pricing Benefit is as follows:

$$\text{Reliability Pricing Benefit} = [.50] * [\text{Change in Total System Capacity Cost}] + [.50] * [\text{Change in Load Capacity Payment}]$$

and

For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to Section (b)(v) of Schedule 12 of the PJM Tariff the Reliability Pricing Benefit is as follows:

$$\text{Reliability Pricing Benefit} = [1] * [\text{Change in Load Capacity Payment}]$$

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion. The Change in the Load Capacity Payment shall be the sum of the change in the Load

Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new Economic-based Enhancement or Expansion, the Office of the Interconnection shall calculate and post on the PJM website the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new Economic-based Enhancements or Expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the Economic-based Enhancement or Expansion, and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of Section 1.5.7(i) of this Schedule 6.

(g) For new economic enhancements or expansions with costs in excess of \$50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new Economic-based Enhancements or Expansions is consistent with the new Economic-based Enhancements or Expansions as recommended in the market efficiency analysis.

(h) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to Parts IV and VI of the PJM Tariff that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a “market solution” and, in the event of such designation, Section 216 of the PJM Tariff, as applicable, shall apply to the project.

(i) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

- (i) Timely installation of Qualifying Transmission Upgrades, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region (“Reliability Assurance Agreement”).
- (ii) Availability of Generation Capacity Resources, as defined by Section 1.33 of the Reliability Assurance Agreement, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the Reliability Assurance Agreement.
- (iii) Availability of Demand Resources that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the Reliability Assurance Agreement.
- (iv) Addition of Customer Facilities pursuant to an executed Interconnection Service Agreement, Facility Study Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed. Facilities with an executed Facilities Study Agreement may be excluded by the Office of the Interconnection after review with the Transmission Expansion Advisory Committee.

- (v) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.
- (vi) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.
- (vii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues and Capacity Resource Clearing Prices under Attachment DD of the PJM Tariff. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues and, if necessary, add transmission enhancements to address congestion that arises from such modeling.
- (viii) Items (i) through (v) will be included in the market efficiency assumptions if qualified for consideration by the PJM Board. In the event that any of the items listed in (i) through (v) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an Economic-based Enhancement or Expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) that the need for the Economic-based Enhancement or Expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(j) For informational purposes only, with regard to Economic-based Enhancements or Expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this Section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses consistent with Section 1.5.3 of this Schedule 6 and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

1.5.8 Development of Long-lead Projects, Short-term Projects, Immediate-need Reliability Projects, and Economic-based Enhancements or Expansions.

(a) Pre-Qualification Process.

(a)(1) On September 1 of each year, the Office of the Interconnection shall open a thirty-day pre-qualification window for entities, including existing Transmission Owners and Nonincumbent Developers, to submit to the Office of the Interconnection: (i) applications to pre-qualify as eligible to be a Designated Entity; or (ii) updated information as described in Section 1.5.8(a)(3) of this Schedule 6. Pre-qualification applications shall contain the following information: (i) name and address of the entity; (ii) the technical and engineering qualifications of the entity or its affiliate, partner, or parent company; (iii) the demonstrated experience of the entity or its affiliate, partner, or parent company to develop, construct, maintain, and operate transmission facilities, including a list or other evidence of transmission facilities the entity, its affiliate, partner, or parent company previously developed, constructed, maintained, or operated; (iv) the previous record of the entity or its affiliate, partner, or parent company regarding construction, maintenance, or operation of transmission facilities both inside and outside of the PJM Region; (v) the capability of the entity or its affiliate, partner, or parent company to adhere to standardized construction, maintenance and operating practices; (vi) the financial statements of the entity or its affiliate, partner, or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the entity, if shorter, or such other evidence demonstrating an entity's or its affiliate's, partner's, or parent company's current and expected financial capability acceptable to the Office of the Interconnection; (vii) a commitment by the entity to execute the Consolidated Transmission Owners Agreement, if the entity becomes a Designated Entity; (viii) evidence demonstrating the ability of the entity or its affiliate, partner, or parent company to address and timely remedy failure of facilities; (ix) a description of the experience of the entity or its affiliate, partner, or parent company in acquiring rights of way; and (x) such other supporting information that the Office of Interconnection requires to make the pre-qualification determinations consistent with this Section 1.5.8(a).

(a)(2) No later than October 31, the Office of the Interconnection shall notify the entities that submitted pre-qualification applications or updated information during the annual thirty-day pre-qualification window, whether they are, or will continue to be, pre-qualified as eligible to be a Designated Entity. In the event the Office of the Interconnection determines that an entity (i) is not, or no longer will continue to be, pre-qualified as eligible to be a Designated Entity, or (ii) provided insufficient information to determine pre-qualification, the Office of the Interconnection shall inform that the entity it is not pre-qualified and include in the notification the basis for its determination. The entity then may submit additional information, which the Office of the Interconnection shall consider in re-evaluating whether the entity is, or will continue to be, pre-qualified as eligible to be a Designated Entity. If the entity submits additional information by November 30, the Office of the Interconnection shall notify the entity of the results of its re-evaluation no later than December 15. If the entity submits additional information after November 30, the Office of the Interconnection shall use reasonable efforts to re-evaluate the application, with the additional information, and notify the entity of its determination as soon as practicable. No later than December 31, the Office of the Interconnection shall post on the PJM website the list of entities that are pre-qualified as eligible

to be Designated Entities. If an entity is notified by the Office of the Interconnection that it does not pre-qualify or will not continue to be pre-qualified as eligible to be a Designated Entity, such entity may request dispute resolution pursuant to Schedule 5 of the Operating Agreement.

(a)(3) If an entity was pre-qualified as eligible to be a Designated Entity in the previous year, such entity is not required to re-submit information to pre-qualify with respect to the upcoming year. In the event the information on which the entity's pre-qualification is based changes with respect to the upcoming year, such entity must submit to the Office of the Interconnection all updated information during the annual thirty-day pre-qualification window and the timeframes for notification in Section 1.5.8(a)(2) of this Schedule 6 shall apply. In the event the information on which the entity's pre-qualification is based changes with respect to the current year, such entity must submit to the Office of the Interconnection all updated information at the time the information changes and the Office of the Interconnection shall use reasonable efforts to evaluate the updated information and notify the entity of its determination as soon as practicable.

(a)(4) As determined by the Office of the Interconnection, an entity may submit a pre-qualification application outside the annual thirty-day pre-qualification window for good cause shown. For a pre-qualification application received outside of the annual thirty-day pre-qualification window, the Office of the Interconnection shall use reasonable efforts to process the application and notify the entity as to whether it pre-qualifies as eligible to be a Designated Entity as soon as practicable.

(a)(5) To be designated as a Designated Entity for any project proposed pursuant to Section 1.5.8 of this Schedule 6, existing Transmission Owners and Nonincumbent Developers must be pre-qualified as eligible to be a Designated Entity pursuant to this Section 1.5.8(a). This Section 1.5.8(a) shall not apply to entities that desire to propose projects for inclusion in the recommended plan but do not intend to be a Designated Entity.

(b) **Posting of Transmission System Needs.** Upon identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, the Office of the Interconnection shall post on the PJM website the violations, system conditions, and economic constraints, and Public Policy Requirements, including (i) federal Public Policy Requirements; (ii) state Public Policy Requirements identified or agreed-to by the states in the PJM Region, which could be addressed by potential Short-term Projects, Long-lead Projects or projects determined pursuant to the State Agreement Approach in Section 1.5.9 of this Schedule 6, as applicable. The Office of the Interconnection also shall post an explanation regarding why transmission needs associated with federal or state Public Policy Requirements were identified but were not selected for further evaluation.

(c) **Project Proposal Windows.** The Office of the Interconnection shall provide notice to stakeholders of a 30-day proposal window for Short-term Projects and a 120-day proposal window for Long-lead Projects and Economic-based Enhancements or Expansions. The Office

of Interconnection may shorten a proposal window should an identified need require a shorter proposal window to meet the needed in-service date of the proposed enhancements or expansions, or extend a proposal window as needed to accommodate updated information regarding system conditions. The Office of the Interconnection may shorten or lengthen a proposal window that is not yet opened based on one or more of the following criteria: (1) complexity of the violation or system condition; and (2) whether there is sufficient time remaining in the relevant planning cycle to accommodate a standard proposal window and timely address the violation or system condition. The Office of the Interconnection may lengthen a proposal window that already is opened based on or more of the following criteria: (i) changes in assumptions or conditions relating to the underlying need for the project, such as load growth or Reliability Pricing Model auction results; (ii) availability of new or changed information regarding the nature of the violations and the facilities involved; and (iii) time remaining in the relevant proposal window. In the event that the Office of the Interconnection determines to lengthen or shorten a proposal window, it will post on the PJM website the new proposal window period and an explanation as to the reasons for the change in the proposal window period. During these windows, the Office of the Interconnection will accept proposals from existing Transmission Owners and Nonincumbent Developers for potential enhancements or expansions to address the posted violations, system conditions, economic constraints, as well as Public Policy Requirements.

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals with cost estimates submitted with the proposals that are under \$20 million, a non-refundable fee must be submitted with each proposal, by each proposing entity who indicates an intention to be the Designated Entity, as follows: a non-refundable fee in the amount of \$5,000 for each project with a cost estimate submitted with the proposal that is equal to or greater than \$20 million and less than \$100 million and a non-refundable fee in the amount of \$30,000 for each project with a cost estimate submitted with the proposal that is equal to \$100 million or greater.

(c)(2) Proposals from all entities (both existing Transmission Owners and Nonincumbent Developers) that indicate the entity intends to be a Designated Entity, also must contain information to the extent not previously provided pursuant to Section 1.5.8(a) demonstrating: (i) technical and engineering qualifications of the entity, its affiliate, partner, or parent company relevant to construction, operation, and maintenance of the proposed project; (ii) experience of the entity, its affiliate, partner, or parent company in developing, constructing, maintaining, and operating the type of transmission facilities contained in the project proposal; (iii) the emergency response capability of the entity that will be operating and maintaining the proposed project; (iv) evidence of transmission facilities the entity, its affiliate, partner, or parent company previously constructed, maintained, or operated; (v) the ability of the entity or its

affiliate, partner, or parent company to obtain adequate financing relative to the proposed project, which may include a letter of intent from a financial institution approved by the Office of the Interconnection or such other evidence of the financial resources available to finance the construction, operation, and maintenance of the proposed project; (vi) the managerial ability of the entity, its affiliate, partner, or parent company to contain costs and adhere to construction schedules for the proposed project, including a description of verifiable past achievement of these goals; (vii) a demonstration of other advantages the entity may have to construct, operate, and maintain the proposed project, including any cost commitment the entity may wish to submit; and (viii) any other information that may assist the Office of the Interconnection in evaluating the proposed project.

(c)(3) The Office of the Interconnection may request additional reports or information from an existing Transmission Owner or Nonincumbent Developers that it determines are reasonably necessary to evaluate its specific project proposal pursuant to the criteria set forth in Sections 1.5.8(e) and 1.5.8(f) of this Schedule 6. If the Office of the Interconnection determines any of the information provided in a proposal is deficient or it requires additional reports or information to analyze the submitted proposal, the Office of the Interconnection shall notify the proposing entity of such deficiency or request. Within 10 business days of receipt of the notification of deficiency and/or request for additional reports or information, or other reasonable time period as determined by the Office of the Interconnection, the proposing entity shall provide the necessary information.

(c)(4) The request for additional reports or information by the Office of the Interconnection pursuant to Section 1.5.8(c)(3) of this Schedule 6 may be used only to clarify a proposed project as submitted. In response to the Office of the Information's request for additional reports or information, the proposing entity (whether an existing Transmission Owner or Nonincumbent Developer) may not submit a new project proposal or modifications to a proposed project once the proposal window is closed. In the event that the proposing entity fails to timely cure the deficiency or provide the requested reports or information regarding a proposed project, the proposed project will not be considered for inclusion in the recommended plan.

(c)(5) Within 30 days of the closing of the proposal window, the Office of the Interconnection may notify the proposing entity that additional per project fees are required if the Office of the Interconnection determines the proposing entity's submittal includes multiple project proposals. Within 10 business days of receipt of the notification of insufficient funds by the Office of the Interconnection, the proposing entity shall submit such funds or notify the Office of the Interconnection which of the project proposals the Office of the Interconnection should evaluate based on the fee(s) submitted.

(d) **Posting and Review of Projects.** Following the close of a proposal window, the Office of the Interconnection shall post on the PJM website all proposals submitted pursuant to Section 1.5.8(c) of this Schedule 6. All proposals addressing state Public Policy Requirements shall be provided to the applicable states in the PJM Region for review and consideration as a Supplemental Project or a state public policy project consistent with Section 1.5.9 of this Schedule 6. The Office of the Interconnection shall review all proposals submitted during a

proposal window and determine and present to the Transmission Expansion Advisory Committee the proposals that merit further consideration for inclusion in the recommended plan. In making this determination, the Office of the Interconnection shall consider the criteria set forth in Sections 1.5.8(e) and 1.5.8(f) of this Schedule 6. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee for review and comment descriptions of the proposed enhancements and expansions, including any proposed Supplemental Projects or state public policy projects identified by a state(s). Based on review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection may, if necessary conduct further study and evaluation. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee the revised enhancements and expansions for review and comment. After consultation with the Transmission Expansion Advisory Committee, the Office of the Interconnection shall determine the more efficient or cost-effective transmission enhancements and expansions for inclusion in the recommended plan consistent with this Schedule 6.

(e) **Criteria for Considering Inclusion of a Project in the Recommended Plan.** In determining whether a Short-term Project or Long-lead Project proposed pursuant to Section 1.5.8(c), individually or in combination with other Short-term Projects or Long-lead Projects, is the more efficient or cost-effective solution and therefore should be included in the recommended plan, the Office of the Interconnection, taking into account sensitivity studies and scenario analyses considered pursuant to Section 1.5.3 of this Schedule 6, shall consider the following criteria, to the extent applicable: (i) the extent to which a Short-term Project or Long-lead Project would address and solve the posted violation, system condition, or economic constraint; (ii) the extent to which the relative benefits of the project meets a Benefit/Cost Ratio Threshold of at least 1.25:1 as calculated pursuant to Section 1.5.7(d) of this Schedule 6; (iii) the extent to which the Short-term Project or Long-lead Project would have secondary benefits, such as addressing additional or other system reliability, operational performance, economic efficiency issues or federal Public Policy Requirements or state Public Policy Requirements identified by the states in the PJM Region; and (iv) other factors such as cost-effectiveness, the ability to timely complete the project, and project development feasibility.

(f) **Entity-Specific Criteria Considered in Determining the Designated Entity for a Project.** In determining whether the entity proposing a Short-term Project or a Long-lead Project recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is pre-qualified to be a Designated Entity pursuant to Section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to Section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s)

agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

(g) **Procedures if No Long-lead Project or Economic-based Enhancement or Expansion Proposal is Determined to be the More Efficient or Cost-Effective Solution.** If the Office of the Interconnection determines that none of the proposed Long-lead Projects received during the Long-lead Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation, or system condition, the Office of the Interconnection may re-evaluate and re-post on the PJM website the unresolved violations, or system conditions pursuant to Section 1.5.8(b), provided such re-evaluation and re-posting would not affect the ability of the Office of the Interconnection to timely address the identified reliability need. In the event that re-posting and conducting such re-evaluation would prevent the Office of the Interconnection from timely addressing the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion, the Office of the Interconnection shall propose a project to solve the posted violation, or system condition for inclusion in the recommended plan and shall present such project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the project is to be located shall be the Designated Entity(ies) for such project. In determining whether there is insufficient time for re-posting and re-evaluation, the Office of the Interconnection shall develop and post on the PJM website a transmission solution construction timeline for input and review by the Transmission Expansion Advisory Committee that will include factors such as, but not limited to: (i) deadlines for obtaining regulatory approvals, (ii) dates by which long lead equipment should be acquired, (iii) the time necessary to complete a proposed solution to meet the required in-service date, and (iv) other time-based factors impacting the feasibility of achieving the required in-service date. Based on input from the Transmission Expansion Advisory Committee and the time frames set forth in the construction timeline, the Office of the Interconnection shall determine whether there is sufficient time to conduct a re-evaluation and re-post and timely address the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion. To the extent that an economic constraint remains unaddressed, the economic constraint will be re-evaluated and re-posted.

(h) **Procedures if No Short-term Project Proposal is Determined to be the More Efficient or Cost-Effective Solution.** If the Office of the Interconnection determines that none of the proposed Short-term Projects received during a Short-term Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation or system condition, the Office of the Interconnection shall propose a Short-term Project to solve the posted violation, or system condition for inclusion in the recommended plan and will present such Short-term Project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the Short-term Project is to be located shall be the Designated Entity(ies) for the Project.

(i) **Notification of Designated Entity.** Within 10 business days of PJM Board approval of the Regional Transmission Expansion Plan, the Office of the Interconnection shall notify the

entities that have been designated as the Designated Entities for projects included in the Regional Transmission Expansion Plan of such designations. In such notices, the Office of the Interconnection shall provide: (i) the needed in-service date of the project; and (ii) a date by which all necessary state approvals should be obtained to timely meet the needed in-service date of the project. The Office of the Interconnection shall use these dates as part of its on-going monitoring of the progress of the project to ensure that the project is completed by its needed in-service date.

(j) **Acceptance of Designation.** Within 30 days of receiving notification of its designation as a Designated Entity, the existing Transmission Owner or Nonincumbent Developer shall notify the Office of the Interconnection of its acceptance of such designation and submit to the Office of the Interconnection a development schedule, which shall include, but not be limited to, milestones necessary to develop and construct the project to achieve the required in-service date, including milestone dates for obtaining all necessary authorizations and approvals, including but not limited to, state approvals. For good cause shown, the Office of the Interconnection may extend the deadline for submitting the development schedule. The Office of the Interconnection then shall review the development schedule and within 15 days or other reasonable time as required by the Office of the Interconnection: (i) notify the Designated Entity of any issues regarding the development schedule identified by the Office of the Interconnection that may need to be addressed to ensure that the project meets its needed in-service date; and (ii) tender to the Designated Entity an executable Designated Entity Agreement setting forth the rights and obligations of the parties. To retain its status as a Designated Entity, within 60 days of receiving notification of its designation (or other such period as mutually agreed upon by the Office of the Interconnection and the Designated Entity), the Designated Entity (both existing Transmission Owners and Nonincumbent Developers) shall submit to the Office of the Interconnection a letter of credit as determined by the Office of Interconnection to cover the incremental costs of construction resulting from reassignment of the project, and return to the Office of the Interconnection an executed Designated Entity Agreement containing a mutually agreed upon development schedule. In the alternative, the Designated Entity may request dispute resolution pursuant to Schedule 5 of this Agreement, or request that the Designated Entity Agreement be filed unexecuted with the Commission.

(k) **Failure of Designated Entity to Meet Milestones.** In the event the Designated Entity fails to comply with one or more of the requirements of Section 1.5.8(j); or fails to meet a milestone in the development schedule set forth in the Designated Entity Agreement that causes a delay of the project's in-service date, the Office of the Interconnection shall re-evaluate the need for the Short-term Project or Long-lead Project, and based on that re-evaluation may: (i) retain the Short-term Project or Long-lead Project in the Regional Transmission Expansion Plan; (ii) remove the Short-term Project or Long-lead Project from the Regional Transmission Expansion Plan; or (iii) include an alternative solution in the Regional Transmission Expansion Plan. If the Office of the Interconnection retains the Short-term or Long-term Project in the Regional Transmission Expansion Plan, it shall determine whether the delay is beyond the Designated Entity's control and whether to retain the Designated Entity or to designate the Transmission Owner(s) in the Zone(s) where the project is located as Designated Entity(ies) for the Short-term Project or Long-lead Project. If the Designated Entity is the Transmission Owner(s) in the Zone(s) where the project is located, the Office of the Interconnection shall seek

recourse through the Consolidated Transmission Owners Agreement or FERC, as appropriate. Any modifications to the Regional Transmission Expansion Plan pursuant to this section shall be presented to the Transmission Expansion Advisory Committee for review and comment and approved by the PJM Board.

(l) **Transmission Owners Required to be the Designated Entity.** Notwithstanding anything to the contrary in this Section 1.5.8, in all events, the Transmission Owner(s) in whose Zone(s) a project proposed pursuant to Section 1.5.8(c) of this Schedule 6 is to be located will be the Designated Entity for the project, when the Short-term Project or Long-lead Project is: (i) a Transmission Owner Upgrade; (ii) located solely within a Transmission Owner's Zone and the costs of the project are allocated solely to the Transmission Owner's Zone; or (iii) located solely within a Transmission Owner's Zone and is not selected in the Regional Transmission Expansion Plan for purposes of cost allocation.

(m) **Immediate-need Reliability Projects:**

(m)(1) Pursuant to the expansion planning process set forth in Sections 1.5.1 through 1.5.6 of Schedule 6, the Office of the Interconnection shall identify immediate reliability needs that must be addressed within three years or less. The Office of the Interconnection shall develop Immediate-need Reliability Projects for which a proposal window pursuant to Section 1.5.8(m)(2) is infeasible. The Office of the Interconnection shall consider the following factors in determining the infeasibility of such a proposal window: (i) nature of the reliability criteria violation; (ii) nature and type of potential solution required; and (iii) projected construction time for a potential solution to the type of reliability criteria violation to be addressed. The Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the Immediate-need Reliability Projects for which a proposal window pursuant to Section 1.5.8(m)(2) is infeasible. The descriptions shall include an explanation of the decision to designate the Transmission Owner as the Designated Entity for the Immediate-need Reliability Project rather than conducting a proposal window pursuant to Section 1.5.8(m)(2), including an explanation of the time-sensitive need for the Immediate-need Reliability Project, other transmission and non-transmission options that were considered but concluded would not sufficiently address the immediate reliability need, the circumstances that generated the immediate reliability need, and why the immediate reliability need was not identified earlier. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments to the Office of the Interconnection. All comments received by the Office of the Interconnection shall be publicly available on the PJM website. Based on the comments received from stakeholders and the review by Transmission Expansion Advisory Committee, the Office of the Interconnection shall, if necessary, conduct further study and evaluation and post a revised recommended plan for review and comment by the Transmission Expansion Advisory Committee. The PJM Board shall approve the Immediate-need Reliability Projects for inclusion in the recommended plan. In January of each year, the Office of the Interconnection shall post on the PJM website and file with the Commission for informational purposes a list of the Immediate-need Reliability Projects for which an existing Transmission Owner was designated in the prior year as the Designated Entity in accordance with this Section 1.5.8(m)(1). The list

shall include the need-by date of Immediate-need Reliability Project and the date the Transmission Owner actually energized the Immediate-need Reliability Project.

(m)(2) If, in the judgment of the Office of the Interconnection, there is sufficient time for the Office of the Interconnection to accept proposals in a shortened proposal window for Immediate-need Reliability Projects, the Office of the Interconnection shall post on the PJM website the violations and system conditions that could be addressed by Immediate-need Reliability Project proposals, including an explanation of the time-sensitive need for an Immediate-need Reliability Project and provide notice to stakeholders of a shortened proposal window. Proposals must contain the information required in Section 1.5.8(c) and, if the entity is seeking to be the Designated Entity, such entity must have pre-qualified to be a Designated Entity pursuant to Section 1.5.8(a). In determining the more efficient or cost-effective proposed Immediate-need Reliability Project for inclusion in the recommended plan, the Office of the Interconnection shall consider the extent to which the proposed Immediate-need Reliability Project, individually or in combination with other Immediate-need Reliability Projects, would address and solve the posted violations or system conditions and other factors such as cost-effectiveness, the ability of the entity to timely complete the project, and project development feasibility in light of the required need. After PJM Board approval, the Office of the Interconnection, in accordance with Section 1.5.8(i) of this Schedule 6, shall notify the entities that have been designated as Designated Entities for Immediate-need Projects included in the Regional Transmission Expansion Plan of such designations. Designated Entities shall accept such designations in accordance with Section 1.5.8(j). In the event that (i) the Office of the Interconnection determines that no proposal resolves a posted violation or system condition; (ii) the proposing entity is not selected to be the Designated Entity; (iii) an entity does not accept the designation as a Designated Entity; or (iv) the Designated Entity fails to meet milestones that would delay the in-service date of the Immediate-need Reliability Project, the Office of the Interconnection shall develop and recommend an Immediate-need Reliability Project to solve the violation or system needs in accordance with Section 1.5.8(m)(1).

(n) ***Reliability Violations on Transmission Facilities Below 200 kV.*** Pursuant to the expansion planning process set forth in Sections 1.5.1 through 1.5.6 of Schedule 6, the Office of the Interconnection shall identify reliability violations on facilities below 200 kV. The Office of the Interconnection shall not post such a violation pursuant to Section 1.5.8(b) of this Schedule 6 for inclusion in a proposal window pursuant to Section 1.5.8(c) unless the identified violation(s) satisfies one of the following exceptions: (i) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV that are impacted by a common contingent element, such that multiple reliability violations could be addressed by one or more solutions, including but not limited to a higher voltage solution; or (ii) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV and the Office of the Interconnection determines that given the location and electrical features of the violations one or more solutions could potentially address or reduce the flow on multiple lower voltage facilities, thereby eliminating the multiple reliability violations. If the reliability violation is identified on multiple facilities rated below 200 kV that are determined by the Office of the Interconnection to meet one of the two exceptions stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with Section 1.5.8(c) of

Schedule 6. If the Office of the Interconnection determines that the identified reliability violations do not satisfy either of the two exceptions stated above, the Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the below 200 kV reliability violations that will not be included in a proposal window pursuant to Section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the below 200 kV reliability violation(s) in a Section 1.5.8(c) proposal window, a description of the facility on which the violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such below 200 kV reliability violation will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. With the exception of Immediate-need Reliability Projects under section 1.5.8(m) of this Schedule 6, PJM will not select an above 200 kV solution for inclusion in the recommended plan that would address a reliability violation on a below 200 kV transmission facility without posting the violation for inclusion in a proposal window consistent with Section 1.5.8(c) of Schedule 6. All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

1.5.9 State Agreement Approach.

(a) State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. As determined by the authorized state governmental entities, such transmission enhancements or expansions may be included in the recommended plan, either as a (i) Supplemental Project or (ii) state public policy project, which is a transmission enhancement or expansion, the costs of which will be recovered pursuant to a FERC-accepted cost allocation proposed by agreement of one or more states and voluntarily agreed to by those state(s). All costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. A state public policy project will be included in the Regional Transmission Expansion Plan for cost allocation purposes only if there is an associated FERC-accepted allocation permitting recovery of the costs of the state public policy project consistent with this Section.

(b) Subject to any designation reserved for Transmission Owners in Section 1.5.8(l) of this Schedule 6, the state(s) responsible for cost allocation for a Supplemental Project or a state public policy project in accordance with Section 1.5.9(a) in this Schedule 6 may submit to the Office of the Interconnection the entity(ies) to construct, own, operate and maintain the state public policy project from a list of entities supplied by the Office of the Interconnection that pre-qualified to be Designated Entities pursuant to Section 1.5.8(a) of this Schedule 6.

1.5.10 Multi-Driver Project.

(a) When a proposal submitted by an existing Transmission Owner or Nonincumbent Developer pursuant to Section 1.5.8(c) meets the definition of a Multi-Driver Project and is designated to be included in the Regional Transmission Expansion Plan for purposes of cost allocation, the Office of the Interconnection shall designate the Designated Entity for the project as follows: (i) if the Multi-Driver Project does not contain a state Public Policy Requirement component, the Office of the Interconnection shall designate the Designated Entity pursuant to the criteria in Section 1.5.8 of this Schedule 6; or (ii) if the Multi-Driver Project contains a state Public Policy Requirement component, the Office of the Interconnection shall evaluate potential Designated Entity candidates based on the criteria in Section 1.5.8 of this Schedule 6, and provide its evaluation to and elicit feedback from the sponsoring state governmental entities responsible for allocation of all costs of the proposed state Public Policy Requirement component (“state governmental entity(ies)”) regarding its evaluation. Based on its evaluation of the Section 1.5.8 criteria and consideration of the feedback from the sponsoring state governmental entity(ies), the Office of the Interconnection shall designate the Designated Entity for the Multi-Driver Project and notify such entity consistent with Section 1.5.8(i) of this Schedule 6. A Multi-Driver Project may be based on proposals that consist of (1) newly proposed transmission enhancements or expansions; (2) additions to, or modifications of, transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan; and/or (3) one or more transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan.

(b) A Multi-Driver Project may contain an enhancement or expansion that addresses a state Public Policy Requirement component only if it meets the requirements set forth in section 1.5.9(a) of this Schedule 6 and its cost allocations are established consistent with Section (b)(xii)(B) of Schedule 12 of the PJM Tariff.

(c) If a state governmental entity(ies) desires to include a Public Policy Requirement component after an enhancement or expansion has been included in the Regional Transmission Expansion Plan, the Office of the Interconnection may re-evaluate the relevant reliability-based enhancement or expansion, Economic-based Enhancement or Expansion, or Multi-Driver Project to determine whether adding the state-sponsored Public Policy Requirement component would create a more cost effective or efficient solution to system conditions. If the Office of the Interconnection determines that adding the state-sponsored Public Policy Requirement component to an enhancement or expansion already included in the Regional Transmission Expansion Plan would result in a more cost effective or efficient solution, the state-sponsored Public Policy Requirement component may be included in the relevant enhancement or expansion, provided all of the requirements of Section 1.5.10(b) of this Schedule 6 are met, and cost allocations are established consistent with Section (b)(xii)(B) of Schedule 12 of the PJM Tariff.

(d) If, subsequent to the inclusion in the Regional Transmission Expansion Plan of a Multi-Driver Project that contains a state Public Policy Requirement component, a state governmental entity(ies) withdraws its support of the Public Policy Requirement component of a Multi-Driver Project, then: (i) the Office of the Interconnection shall re-evaluate the need for the remaining components of the Multi-Driver Project without the state Public Policy Requirement

component, remove the Multi-Driver Project from the Regional Transmission Expansion Plan, or replace the Multi-Driver Project with an enhancement or expansion that addresses remaining reliability or economic system needs; (ii) if the Multi-Driver Project is retained in the Regional Transmission Expansion Plan without the state Public Policy Requirement component, the costs of the remaining components will be allocated in accordance with Schedule 12 of the Tariff; (iii) if more than one state is responsible for the costs apportioned to the state Public Policy Requirement component of the Multi-Driver Project, the remaining state governmental entity(ies) shall have the option to continue supporting the state Public Policy component of the Multi-Driver Project and if the remaining state governmental entity(ies) choose this option, the apportionment of the state Public Policy Requirement component will remain in place and the remaining state governmental entity(ies) shall agree upon their respective apportionments; (iv) if a Multi-Driver Project must be retained in the Regional Transmission Expansion Plan and completed with the State Public Policy component, the state Public Policy Requirement apportionment will remain in place and the withdrawing state governmental entity(ies) shall continue to be responsible for its/their share of the FERC-accepted cost allocations as filed pursuant to Section (b)(xii)(B) of Schedule 12 of the PJM Tariff.

(e) The actual costs of a Multi-Driver Project shall be apportioned to the different components (reliability-based enhancement or expansion, Economic-based Enhancement or Expansion and/or Public Policy Requirement) based on the initial estimated costs of the Multi-Driver Project in accordance with the methodology set forth in Schedule 12 of the PJM Tariff.

(f) The benefit metric calculation used for evaluating the market efficiency component of a Multi-Driver Project will be based on the final voltage of the Multi-Driver Project using the Benefit/Cost Ratio calculation set forth in Section 1.5.7(d) of Schedule 6 of this Operating Agreement where the Cost component of the calculation is the present value of the estimated cost of the enhancement apportioned to the market efficiency component of the Multi-Driver Project for each of the first 15 years of the life of the enhancement or expansion.

(g) Except as provided to the contrary in this Section 1.5.10, Section 1.5.8 of this Schedule 6 applies to Multi-Driver Projects.

(h) The Office of the Interconnection shall determine whether a proposal(s) meets the definition of a Multi-Driver Project by identifying a more efficient or cost effective solution that uses one of the following methods: (i) combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project (“Proportional Multi-Driver Method”); or (ii) expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers (“Incremental Multi-Driver Method”).

(i) In determining whether a Multi-Driver Project may be designated to more than one entity, PJM shall consider whether: (i) the project consists of separable transmission elements, which are physically discrete transmission components, such as, but not limited to, a transformer, static var compensator or definable linear segment of a transmission line, that can be designated individually to a Designated Entity to construct and own and/or finance; and (ii) each

entity satisfies the criteria set forth in section 1.5.8(f) of Schedule 6. Separable transmission elements that qualify as Transmission Owner Upgrades shall be designated to the Transmission Owner in the Zone in which the facility will be located.

1.6 Approval of the Final Regional Transmission Expansion Plan.

- (a) Based on the studies and analyses performed by the Office of the Interconnection under this Schedule 6, the PJM Board shall approve the Regional Transmission Expansion Plan in accordance with the requirements of this Schedule 6. The PJM Board shall approve the cost allocations for transmission enhancements and expansions consistent with Schedule 12 of the PJM Tariff. Supplemental Projects shall be integrated into the Regional Transmission Expansion Plan approved by the PJM Board but shall not be included for cost allocation purposes.
- (b) The Office of the Interconnection shall publish the current, approved Regional Transmission Expansion Plan on the PJM Internet site. Within 30 days after each occasion when the PJM Board approves a Regional Transmission Expansion Plan, or an addition to such a plan, that designates one or more Transmission Owner(s) or Designated Entity(ies) to construct such expansion or enhancement, the Office of the Interconnection shall file with FERC a report identifying the expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Section 1.5.6(l) above to bear responsibility for the costs of the project.
- (c) If a Regional Transmission Expansion Plan is not approved, or if the transmission service requested by any entity is not included in an approved Regional Transmission Expansion Plan, nothing herein shall limit in any way the right of any entity to seek relief pursuant to the provisions of Section 211 of the Federal Power Act.
- (d) Following PJM Board approval, the final Regional Transmission Expansion Plan shall be documented, posted publicly and provided to the Applicable Regional Entities.

1.7 Obligation to Build.

- (a) Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners or Designated Entities designated as the appropriate entities to construct, own and/or finance enhancements or expansions specified in the Regional Transmission Expansion Plan shall construct, own and/or finance such facilities or enter into appropriate contracts to fulfill such obligations. Except as provided in Section 1.5.8(k) of this Schedule 6, nothing herein shall require any Transmission Owner to construct, finance or own any enhancements or expansions specified in the Regional Transmission Expansion Plan for which the plan designates an entity other than a Transmission Owner as the appropriate entity to construct, own and/or finance such enhancements or expansions.
- (b) Nothing herein shall prohibit any Transmission Owner from seeking to recover the cost of enhancements or expansions on an incremental cost basis or from seeking approval of such rate treatment from any regulatory agency with jurisdiction over such rates.
- (c) The Office of the Interconnection shall be obligated to collect on behalf of the Transmission Owner(s) or Designated Entity(ies) all charges established under Schedule 12 of the PJM Tariff in connection with facilities which the Office of the Interconnection designates one or more Transmission Owners or Designated Entity(ies) to build pursuant to this Regional Transmission Expansion Planning Protocol. Such charges shall compensate the Transmission Owner(s) or Designated Entity(ies) for all costs related to such RTEP facilities under a FERC-approved rate and will include any FERC-approved incentives.
- (d) In the event that a Transmission Owner declines to construct an economic transmission enhancement or expansion developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the Office of the Interconnection shall promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit the FERC to determine what action, if any, it should take.

1.8 Interregional Expansions

- (a) PJM shall collect from Midwest Independent System Operator, Inc., for distribution to the applicable Transmission Owners, in accordance with Schedule 12 of the PJM Tariff, revenues collected by the Midwest Independent System Operator, Inc. under the Open Access Transmission Tariff of the Midwest Independent System Owner, Inc. with respect to transmission enhancements or expansions for which the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility for transmission enhancements or expansions in the PJM Region to market participants in the region of the Midwest Independent System Operator, Inc.
- (b) PJM shall disburse to the Midwest Independent System Operator, Inc., for distribution to applicable transmission owners of the Midwest Independent System Operator, Inc., revenues collected under Schedule 12 of the PJM Tariff which establishes a charge in connection with enhancements or expansions in the region of the Midwest Independent System Operator, Inc. the cost responsibility for which has been assigned to market participants in the PJM Region under the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.
- (c) Nothing in this Section 1.8 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the PJM Tariff and applicable agreements.

1.9 Relationship to the PJM Open Access Transmission Tariff.

Nothing herein shall modify the rights and obligations of an Eligible Customer or a Transmission Customer, as those terms are defined in the PJM Tariff, with respect to required studies and completion of necessary enhancements or expansions. An Eligible Customer or Transmission Customer electing to follow the procedures in the PJM Tariff instead of the procedures provided herein, shall also be responsible for the related costs. The enhancement and expansion study process under this Protocol shall be funded as a part of the operating budget of the Office of the Interconnection.

SCHEDULE 6-A

Interregional Transmission Coordination Between the SERTP and PJM Regions

The Office of the Interconnection, through its regional transmission planning process, coordinates with the public utility transmission providers of Southeastern Regional Transmission Planning (“SERTP,” and individually, “SERTP Transmission Provider,” and collectively, “SERTP Transmission Providers”), as the transmission providers and planners for the SERTP region to address transmission planning coordination issues related to interregional transmission projects. The interregional transmission coordination procedures include a detailed description of the process for coordination between the SERTP Transmission Providers and the Office of the Interconnection, to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than transmission projects included in the respective regional transmission plans. The interregional transmission coordination procedures are hereby provided in this Schedule 6-A with additional materials provided on the PJM Regional Planning website.

The Office of the Interconnection and each of the SERTP Transmission Providers shall:

- (1) Coordinate and share the results of the SERTP Transmission Providers’ and the Office of the Interconnection’s regional transmission plans to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than separate regional transmission projects;
- (2) Identify and jointly evaluate transmission projects that are proposed to be located in both transmission planning regions;
- (3) Exchange, at least annually, planning data and information; and
- (4) Maintain a website and e-mail list for the communication of information related to the coordinated planning process.

The SERTP Transmission Providers and the Office of the Interconnection developed a mutually agreeable method for allocating between the two transmission planning regions the costs of new interregional transmission projects that are located within both transmission planning regions. Such cost allocation method satisfies the six interregional cost allocation principles set forth in Order No. 1000 and are included in this Schedule 12-B of the PJM Open Access Transmission Tariff (“Schedule 12-B”).

For purposes of this Schedule 6-A, each of the SERTP Transmission Provider’s transmission planning process is the process described in each of the SERTP Transmission Providers’ open access transmission tariffs; the Office of the Interconnection’s regional transmission planning process is the process described in Schedule 6 of this Agreement. References to the respective transmission planning processes in each of the SERTP Transmission Providers’ open access transmission tariffs are intended to identify the activities described in those tariff provisions. References to the respective regional transmission plans in this Schedule 6-A are intended to identify, for the Office of the Interconnection, the PJM Regional

Transmission Expansion Plan (“RTEP”), as defined in applicable PJM documents and, for the each SERTP Transmission Providers, the SERTP regional transmission plan which includes the applicable ten (10) year transmission expansion plan. Unless noted otherwise, Section references in this Schedule 6-A refer to Sections within this Schedule 6-A.

Nothing in this Schedule 6-A is intended to affect the terms of any bilateral planning or operating agreements between transmission owners and/or transmission service providers that exist as of the effective date of this Schedule 6-A or that are executed at some future date.

INTERREGIONAL TRANSMISSION PLANNING PRINCIPLES

Representatives of the SERTP and the Office of the Interconnection will meet no less than once per year to facilitate the interregional coordination procedures described below (as applicable). Representatives of the SERTP and the Office of the Interconnection may meet more frequently during the evaluation of project(s) proposed for purposes of interregional cost allocation between the SERTP and the Office of the Interconnection. For purposes of this Schedule 6-A, an “interregional transmission project” means a facility or set of facilities that would be physically located in both the SERTP and PJM regions and would interconnect to transmission facilities in both the SERTP and PJM regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan that are currently under development.

1. Coordination

1.1 Review of Respective Regional Transmission Plans: Biennially, the Office of the Interconnection and the SERTP Transmission Providers shall review each other’s current regional transmission plan(s) and engage in the data exchange and joint evaluation described in Sections 2 and 3.

1.1.1 The review of each region’s regional transmission plan(s), which plans include the transmission needs and planned upgrades of the transmission providers in each region, shall occur on a mutually agreeable timetable, taking into account each region’s transmission planning process timeline.

1.2 Review of Proposed Interregional Transmission Projects: The SERTP Transmission Providers and the Office of the Interconnection will also coordinate with regard to the evaluation of interregional transmission projects identified by the SERTP Transmission Providers and the Office of the Interconnection as well as interregional transmission projects proposed for Interregional Cost Allocation Purposes (“Interregional CAP”), pursuant to Sections 3 below and Schedule 12-B of the PJM Open Access Transmission Tariff. Initial coordination activities regarding new interregional proposals will typically begin during the third calendar quarter. The SERTP Transmission Providers and the Office of the Interconnection will exchange status updates for new interregional transmission project proposals or proposals currently under consideration as needed. These status updates will generally include, if applicable: (i) an update of the region’s evaluation of the proposal; (ii) the latest calculation of Regional Benefits (as

defined in Schedule 12-B); (iii) the anticipated timeline for future assessments; and (iv) reevaluations related to the proposal.

1.3 Coordination of Assumptions Used in Joint Evaluation: The SERTP Transmission Providers and the Office of the Interconnection will coordinate assumptions used in joint evaluations, as necessary, which includes items such as:

- 1.3.1 Expected timelines/milestones associated with the joint evaluation
- 1.3.2 Study assumptions
- 1.3.3 Regional benefit calculations

1.4 Posting of Materials on Regional Planning Websites: The SERTP Transmission Providers and the Office of the Interconnection will coordinate with respect to the posting of materials related to the interregional coordination procedures described in this Schedule 6-A on each region's regional planning website.

2. Data Exchange

2.1 At least annually, each of the SERTP Transmission Providers and the Office of the Interconnection shall exchange power-flow models and associated data used in the regional transmission planning processes to develop their respective then-current regional transmission plan(s). This exchange will occur when such data is available in each of the transmission planning processes, typically during the first calendar quarter. Additional transmission-based models and data may be exchanged between the SERTP Transmission Providers and the Office of the Interconnection as necessary and if requested. For purposes of the interregional coordination activities outlined in this Schedule 6-A, only data and models used in the development of the SERTP Transmission Provider's and the Office of the Interconnection's then-current regional transmission plans and used in their respective regional transmission planning processes will be exchanged. This data will be posted on the pertinent regional transmission planning process' websites, consistent with the posting requirements of the respective regional transmission planning processes, and is considered CEII. The Office of the Interconnection shall notify the SERTP Transmission Providers of such posting.

2.2 The RTEP will be posted on the Office of the Interconnection's Regional Planning website pursuant to the Office of the Interconnection's regional transmission planning process. The Office of the Interconnection shall notify the SERTP Transmission Providers of such posting so that the SERTP Transmission Providers may retrieve these transmission plans. Each of the SERTP Transmission Providers will exchange its then-current regional plan(s) in a similar manner according to its regional transmission planning process.

3. Joint Evaluation

3.1 Identification of Interregional Transmission Projects: The SERTP Transmission Providers and the Office of the Interconnection shall exchange planning models and data and current regional transmission plans as described in Section 2. Each SERTP Transmission Provider and the Office of the Interconnection will review one another's then-current regional transmission plan(s) in accordance with the coordination procedures described

in Section 1 and their respective regional transmission planning processes. If through this review, a SERTP Transmission Provider and the Office of the Interconnection identify a potential interregional transmission project that could be more efficient or cost effective than projects included in the respective regional plans, the SERTP Transmission Provider and the Office of the Interconnection will jointly evaluate the potential project pursuant to Section 3.3.

3.2 Identification of Interregional Transmission Projects by Stakeholders:

Stakeholders may propose projects that may be more efficient or cost-effective than projects included in the SERTP Transmission Providers' and the Office of the Interconnection's regional transmission plans pursuant to the procedures in each region's regional transmission planning processes. The SERTP Transmission Providers and Office of the Interconnection will evaluate interregional transmission projects proposed by stakeholders pursuant to Section 3.3.

3.3 Evaluation of Interregional Transmission Projects: The SERTP Transmission Providers and the Office of the Interconnection shall act through their respective regional transmission planning processes to evaluate potential interregional transmission projects and to determine whether the inclusion of any potential interregional transmission projects in each region's regional transmission plan would be more efficient or cost-effective than projects included in the respective then-current regional transmission plans. Such analysis shall be consistent with accepted planning practices of the respective regions and the methods utilized to produce each region's respective regional transmission plan(s). The Office of the Interconnection will evaluate potential interregional transmission projects consistent with Schedule 6 and the PJM Manuals 14A entitled Generation and Transmission Interconnection Process and 14B entitled PJM Region Transmission Planning Process on the PJM Website at <http://www.pjm.com/documents/manuals.aspx>. To the extent possible and as needed, assumptions and models will be coordinated between the SERTP Transmission Providers and the Office of the Interconnection, as described in Section 1. Data shall be exchanged to facilitate this evaluation using the procedures described in Section 2.

3.4 Evaluation of Interregional Transmission Projects Proposed for Interregional Cost Allocation Purposes: Interregional transmission projects proposed for Interregional CAP must be submitted in both the SERTP and PJM regional transmission planning processes. The project submittals must satisfy the applicable requirements for submittal of interregional transmission projects, including those in Schedule 6 of this Agreement and Schedule 12-B of the PJM Tariff. The submittals in the respective regional transmission planning processes must identify the project proposal as interregional in scope and identify SERTP and PJM as the regions in which the project is proposed to interconnect. The Office of the Interconnection will determine whether the submittal for the proposed interregional transmission project satisfies all applicable requirements. Upon finding that the project submittal satisfies all such applicable requirements, the Office of the Interconnection will notify the SERTP Transmission Provider. Upon both regions so notifying one another that the project is eligible for consideration pursuant to their respective regional transmission planning processes, the SERTP Transmission Provider and the Office of the Interconnection will jointly evaluate the proposed interregional projects.

3.4.1 If an interregional transmission project is proposed in the SERTP and Office of Interconnection for Interregional CAP, the initial evaluation of the project will typically begin during the third calendar quarter, with analysis conducted in the same manner as analysis of interregional projects identified pursuant to Sections 3.1 and 3.2. Further evaluation shall also be performed pursuant to this Section 3.4. Projects proposed for Interregional CAP shall also be subject to the requirements of Schedule 12-B.

3.4.2. Each region, acting through its regional transmission planning process, will evaluate proposals to determine whether the interregional transmission project(s) proposed for Interregional CAP addresses transmission needs that are currently being addressed with projects in its regional transmission plan(s) and, if so, which projects in the regional transmission plan(s) could be displaced by the proposed project(s).

3.4.3. Based upon its evaluation, each region will quantify a Regional Benefit based upon the transmission costs that each region is projected to avoid due to its transmission projects being displaced by the proposed project. For purposes of this Schedule 6-A, "Regional Benefit" means: (i) for the SERTP Transmission Providers, the total avoided costs of projects included in the then-current regional transmission plan that would be displaced if the proposed interregional transmission project was included and (ii) for the Office of the Interconnection, the total avoided costs of projects included in the then-current regional transmission plan that would be displaced if the proposed interregional transmission project was included. The Regional Benefit is not necessarily the same as the benefits used for purposes of regional cost allocation.

3.5 Inclusion of Interregional Projects Proposed for Interregional CAP in Regional Transmission Plans: An interregional transmission project proposed for Interregional CAP in the SERTP and Office of the Interconnection will be included in the respective regional plans for purposes of cost allocation only after it has been selected by both the SERTP and Office of the Interconnection regional processes to be included in their respective regional plans for purposes of cost allocation.

3.5.1. To be selected in both the SERTP and Office of the Interconnection regional plans for purposes of cost allocation means that each region has performed all evaluations, as prescribed in its regional transmission planning processes, necessary for a project to be included in its regional transmission plans for purposes of cost allocation.

- For SERTP: All requisite approvals are obtained, as prescribed in the SERTP regional transmission planning process, necessary for a project to be included in the SERTP regional transmission plan for purposes of cost allocation. This includes any requisite regional benefit to cost ("BTC") ratio calculations performed pursuant to the respective regional transmission planning processes. For purposes of the SERTP, the anticipated allocation of costs of the interregional transmission project for use in the regional BTC ratio calculation shall be based upon the ratio of the SERTP's Regional Benefit to the sum of the Regional Benefits identified for both the SERTP and the Office of the Interconnection; and

- For the Office of Interconnection: All requisite approvals are obtained, as prescribed in the PJM regional transmission planning process, necessary for a project to be included in the RTEP for purposes of cost allocation.

3.6 Removal from Regional Plans: An interregional transmission project may be removed from the SERTP's or Office of the Interconnection's regional plan for purposes of cost allocation: (i) if the developer fails to meet developmental milestones; (ii) pursuant to the reevaluation procedures specified in the respective regional transmission planning processes; or (iii) if the project is removed from one of the region's regional transmission plan(s) pursuant to the requirements of its regional transmission planning process.

3.6.1 The Office of the Interconnection, shall notify the SERTP Transmission Provider if an interregional project or a portion thereof is likely to be removed from its regional transmission plan.

4. **Transparency**

4.1 The Office of the Interconnection shall post procedures for coordination and joint evaluation on the Regional Planning website.

4.2 Access to the data utilized will be made available through the Regional Planning website subject to the appropriate clearance, as applicable (such as CEII and confidential non-CEII). Both planning regions will make available, on their respective regional websites, links to where stakeholders can register (if applicable/available) for the stakeholder committees or distribution lists of the other planning region.

4.3 PJM will provide status updates of SERTP interregional activities to the TEAC including:

- Facilities to be evaluated
- Analysis performed
- Determinations/results.

4.4 Stakeholders will have an opportunity to provide input and feedback within the respective regional planning processes of SERTP and the Office of the Interconnection related to interregional facilities identified, analysis performed, and any determination/results. Stakeholders may participate in either or both regions' regional planning processes to provide their input and feedback regarding the interregional coordination between the SERTP and the Office of the Interconnection.

4.5 The Office of the Interconnection will post a list on the Regional Planning Website of interregional transmission projects proposed for purposes of cost allocation in both the SERTP and PJM that are not eligible for consideration because they do not satisfy the regional project threshold criteria of one or both of the regions as well as post an explanation of the thresholds the proposed interregional project failed to satisfy.

SCHEDULE 6-B
Interregional Transmission Coordination Between
PJM, New York Independent System Operator, Inc. and ISO New England Inc.

PJM, its Transmission Owners, and any other interested parties shall coordinate system planning activities with neighboring planning regions, (*i.e.*, New York Independent System Operator, Inc. and ISO New England Inc.) (“ISO/RTO Regions”) pursuant to the Northeastern Planning Protocol (“Protocol”) identified at section 1.5.5(b) of Schedule 6 herein.

The Interregional Planning Protocol includes a description of the committee structure, processes, and procedures through which system planning activities are openly and transparently coordinated by the ISO/RTO Regions. The objective of the interregional planning process is to contribute to the on-going reliability and the enhanced operational and economic performance of the ISO/RTO Regions through: (i) exchange of relevant data and information; (ii) coordination of procedures to evaluate certain interconnection and transmission service requests; (iii) periodic comprehensive interregional assessments; (iv) identification and evaluation of potential Interregional Transmission Projects that can address regional needs in a manner that may be more efficient or cost-effective than separate regional solutions, in accordance with the requirements of Order No. 1000.

Section 9 of the Protocol indicates that the cost allocation for identified interregional transmission projects between PJM and NYISO shall be conducted in accordance with the Joint Operating Agreement Among and Between New York Independent System Operator, Inc. and PJM Interconnection, L.L.C. referenced at section 1.5.5(b) of this Schedule 6

The planning activities of the ISO/RTO Regions shall be conducted consistent with the planning criteria of each ISO/RTO Region. The ISO/RTO Regions shall periodically produce a Northeastern Coordinated System Plan that integrates the system plans of all of the ISO/RTO Regions.

**SCHEDULE 7 -
UNDERFREQUENCY RELAY OBLIGATIONS AND CHARGES**

1. UNDERFREQUENCY RELAY OBLIGATION

1.1 Application.

The obligations of this Schedule apply to each Member that is an Electric Distributor, whether or not that Member participates in the Electric Distributor sector on the Members Committee or meets the eligibility requirements for any other sector of the Members Committee.

1.1A Counterparty.

PJMSettlement is the Counterparty to obligations and all payments and distributions associated with underfrequency relay obligations and charges pursuant to this Schedule 7.

1.2 Obligations.

- (a) Each Electric Distributor in the PJM Mid-Atlantic Region shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 58.9 Hz and 58.5 Hz. Upon the request of the Members Committee, each Electric Distributor in the PJM Mid-Atlantic Region shall document that it has complied with the requirement for underfrequency load shedding relays.
- (b) Each Electric Distributor in the PJM West Region shall install or contractually arrange for underfrequency relays to interrupt at least 25 percent of its peak load with 5 percent of the load interrupted at each of five frequency levels: 59.5 Hz, 59.3 Hz, 59.1 Hz, 58.9 Hz, and 58.7 Hz; provided, however, that each Electric Distributor in the Commonwealth Edison Company Zone shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 59.0 Hz, and 58.7 Hz. Upon the request of the Markets and Reliability Committee established by the Reliability Assurance Agreement, each Electric Distributor in the PJM West Region shall document that it has complied with the requirement for underfrequency load shedding relays.
- (c) Each Electric Distributor in the PJM South Region shall install or contractually arrange for underfrequency relays to interrupt at least 30 percent of its peak load with 10 percent of the load interrupted at each of 3 frequency levels: 59.3 Hz, 59.0 Hz, 58.5 Hz. Upon the request of the Markets and Reliability Committee established by the Reliability Assurance Agreement, each Electric Distributor in the PJM South Region shall document that it has complied with the requirement for underfrequency load shedding relays.

2. UNDERFREQUENCY RELAY CHARGES

If an Electric Distributor is determined to not have the required underfrequency relays, it shall pay an underfrequency relay charge of:

$$\text{Charge} = D \times R \times 365$$

where

D = the amount, in megawatts, the Electric Distributor is deficient; and

R = the daily rate per megawatt, which shall be based on the annual carrying charges for a new combustion turbine generator, installed and connected to the transmission system, which daily deficiency rate as of the Effective Date shall be \$58.400/per kilowatt-year or \$160 per megawatt-day.

3. DISTRIBUTION OF UNDERFREQUENCY RELAY CHARGES

3.1 Share of Charges.

Each Electric Distributor that has complied with the requirements for underfrequency relays imposed by this Agreement during a Planning Period, without incurring an underfrequency relay charge, shall share in any underfrequency relay charges paid by any other Electric Distributor that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the number of megawatts of a Electric Distributor's load in the most recently completed month at the time of the peak for the PJM Region during that month rounded to the next higher whole megawatt, as established initially on the Effective Date and as updated at the beginning of each month thereafter.

3.2 Allocation by the Office of the Interconnection.

In the event all of the Electric Distributors have incurred underfrequency relay charges during a Planning Period, the underfrequency relay charges shall be distributed among the Electric Distributors on an equitable basis as determined by the Office of the Interconnection.

**SCHEDULE 8 -
DELEGATION OF PJM REGION RELIABILITY RESPONSIBILITIES**

1. DELEGATION

The following responsibilities shall be delegated to the Office of the Interconnection by the parties to the Reliability Assurance Agreement.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall:

- (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Reliability Assurance Agreement; and
- (b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT

With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall:

- (a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners or providers of Capacity Resources;
- (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards, as the foregoing terms are defined in the Reliability Assurance Agreement;
- (c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement;
- (d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement;
- (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;
- (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;
- (g) Establish standards and procedures for Planned Demand Resources;
- (h) Collect and maintain generator availability data;
- (i) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement;
- (j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;
- (k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;
- (l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and
- (m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional

Reliability Council principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 9

[Reserved for Future Use]

SCHEDULE 10 - FORM OF NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (the “Agreement”) is made this ____ day of _____, 20__, by and between _____, an Authorized Person, as defined below, and PJM Interconnection, L.L.C., a Delaware limited liability company, with offices at 2750 Monroe Blvd., Audubon, PA 19403 (“PJM”). The Authorized Person and PJM shall be referred to herein individually as a “Party,” or collectively as the “Parties.”

RECITALS

Whereas, PJM serves as the Regional Transmission Organization with reliability and/or functional control responsibilities over transmission systems involving fourteen states including the District of Columbia, and operates and oversees wholesale markets for electricity pursuant to the requirements of the PJM Tariff and the Operating Agreement, as defined below; and

Whereas, the PJM Market Monitor serves as the monitor for PJM’s wholesale markets for electricity, and

Whereas, the Operating Agreement requires that PJM and the PJM Market Monitor maintain the confidentiality of Confidential Information; and

Whereas, the Operating Agreement requires PJM and the PJM Market Monitor to disclose Confidential Information to Authorized Persons upon satisfaction of conditions stated in the Operating Agreement, which may include, but are not limited to, the execution of this Agreement by the Authorized Person and the maintenance of the confidentiality of such information pursuant to the terms of this Agreement; and

Whereas, PJM desires to provide Authorized Persons with the broadest possible access to Confidential Information, consistent with PJM’s and the PJM Market Monitor’s obligations and duties under the PJM Operating Agreement, the PJM Tariff and other applicable FERC directives; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of the Operating Agreement, whereby PJM or the PJM Market Monitor may provide Confidential Information to the Authorized Person.

NOW, THEREFORE, intending to be legally bound, the Parties hereby agree as follows:

1. DEFINITIONS.

1.1 Affected Member.

A Member of PJM which as a result of its participation in PJM's markets or its membership in PJM provided Confidential Information to PJM, which Confidential Information is requested by, or is disclosed to an Authorized Person under this Agreement.

1.2 Authorized Commission.

(i) A State (which shall include the District of Columbia) public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

1.3 Authorized Person.

A person, including the undersigned, which has executed this Agreement and is authorized in writing by an Authorized Commission to receive and discuss Confidential Information. Authorized Persons may include attorneys representing an Authorized Commission or consultants and/or contractors directly employed or retained by an Authorized Commission, provided however that consultants or contractors may not initiate requests for Confidential Information from PJM or the PJM Market Monitor.

1.4 Confidential Information.

Any information that would be considered non-public or confidential under the Operating Agreement.

1.5 FERC.

The Federal Energy Regulatory Commission.

1.6 Information Request.

A written request, in accordance with the terms of this Agreement for disclosure of Confidential Information pursuant to Section 18.17.4 of the Operating Agreement.

1.7 Operating Agreement.

The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., as it may be further amended or restated from time to time.

1.8 PJM Market Monitor.

The Market Monitoring Unit established under Attachment M to the PJM Tariff.

1.9 PJM Tariff.

The PJM Open Access Transmission Tariff, as it may be amended from time to time.

1.10 Third Party Request.

Any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for Confidential Information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

2. Protection of Confidentiality.

2.1 Duty to Not Disclose.

The Authorized Person represents and warrants that he or she: (i) is presently an Authorized Person as defined herein; (ii) is duly authorized to enter into and perform this Agreement; (iii) has adequate procedures to protect against the release of Confidential Information, and (iv) is familiar with, and will comply with, all such applicable Authorized Commission procedures. The Authorized Person hereby covenants and agrees on behalf of himself or herself to deny any Third Party Request and defend against any legal process which seeks the release of Confidential Information in contravention of the terms of this Agreement.

2.2 Discussion of Confidential Information with Other Authorized Persons.

The Authorized Person may discuss Confidential Information with employees of the Authorized Commission who have been designated Authorized Persons pursuant to the Operating Agreement and with such other third-party. Authorized Persons who have executed non-disclosure agreements with PJM containing the same terms and conditions as this Agreement.

2.3 Defense Against Third Party Requests.

The Authorized Person shall defend against any disclosure of Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, seeking to obtain any necessary protective orders. The Authorized Person shall provide PJM, and PJM shall provide each Affected Member, with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Person agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM (and of which PJM shall, in turn, advise any Affected Members) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

2.4 Care and Use of Confidential Information.

2.4.1 Control of Confidential Information.

The Authorized Person(s) shall be the custodian(s) of any and all Confidential Information received pursuant to the terms of this Agreement from PJM or the PJM Market Monitor.

2.4.2 Access to Confidential Information.

The Authorized Person shall ensure that Confidential Information received by that Authorized Person is disseminated only to those persons publicly identified as Authorized Persons on Exhibit "A" to the certification provided by the State Commission to PJM pursuant to the procedures contained in section 18.17.4 of the Operating Agreement.

2.4.3 Schedule of Authorized Persons.

- (i) The Authorized Person shall promptly notify PJM and the PJM Market Monitor of any change that would affect the Authorized Person's status as an Authorized Person, and in such event shall request, in writing, deletion from the schedule referred to in section (ii), below.
- (ii) PJM shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on the PJM website and/or by written request. Such schedule shall be compiled by PJM, based on information provided by any Authorized Person and/or Authorized Commission. PJM shall update the schedule promptly upon receipt of information from an Authorized Person or Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by PJM in the compilation and/or maintenance of the schedule.

2.4.4 Use of Confidential Information.

The Authorized Person shall use the Confidential Information solely for the purpose of assisting the Authorized Commission in discharging its legal responsibility to monitor the wholesale and retail electricity markets, operations, transmission planning and siting and generation planning and siting materially affecting retail customers within the State, and for no other purpose.

2.4.5 Return of Confidential Information.

Upon completion of the inquiry or investigation referred to in the Information Request, or for any reason the Authorized Person is, or will no longer be an Authorized Person, the Authorized Person shall (a) return the Confidential Information and all copies thereof to PJM and/or the PJM Market Monitor, or (b) provide a certification that the Authorized Person has destroyed all paper copies and deleted all electronic copies of the Confidential Information. PJM and/or the PJM Market Monitor, as applicable, may waive this condition in writing if such Confidential Information has become publicly available or non-confidential in the course of business or

pursuant to the PJM Tariff, PJM rule or order of the FERC.

2.4.6 Notice of Disclosures.

The Authorized Person, directly or through the Authorized Commission, shall promptly notify PJM and/or the PJM Market Monitor, and PJM and/or the PJM Market Monitor shall promptly notify any Affected Member, of any inadvertent or intentional release or possible release of the Confidential Information provided pursuant to this Agreement. The Authorized Person shall take all steps to minimize any further release of Confidential Information, and shall take reasonable steps to attempt to retrieve any Confidential Information that may have been released.

2.5 Ownership and Privilege.

Nothing in this Agreement, or incident to the provision of Confidential Information to the Authorized Person pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM and/or the PJM Market Monitor, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM, the PJM Market Monitor (to the extent that it owns any intellectual property), and/or the Affected Member.

3. Remedies.

3.1 Material Breach.

The Authorized Person agrees that release of Confidential Information to persons not authorized to receive it constitutes a breach of this Agreement and may cause irreparable harm to PJM and/or the Affected Member. In the event of a breach of this Agreement by the Authorized Person, PJM shall terminate this Agreement upon written notice to the Authorized Person and his or her Authorized Commission, and all rights of the Authorized Person hereunder shall thereupon terminate; provided, however, that PJM may restore an individual's status as an Authorized Person after consulting with the Affected Member and to the extent that: (i) PJM determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Person; (ii) there were no harm or damages suffered by the Affected Member; or (iii) similar good cause shown. Any appeal of PJM's actions under this section shall be to FERC.

3.2 Judicial Recourse.

In the event of any breach of this Agreement, PJM and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all Confidential Information to PJM. The Authorized Person expressly agrees that in the event of a breach of this Agreement, any relief sought properly includes, but shall not be limited to, the immediate return of all Confidential Information to PJM.

3.3 Waiver of Monetary Damages.

No Authorized Person shall have responsibility or liability whatsoever under this Agreement for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of, or in connection with, the release of Confidential Information to persons not authorized to receive it. Nothing in this Section 3.3 is intended to limit the liability of any person who is not under contract to provide services to an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

4. Jurisdiction.

The Parties agree that (i) any dispute or conflict requesting the relief in sections 3.1, and 3.2(a) above shall be submitted to FERC for hearing and resolution; (ii) any dispute or conflict requesting the relief in section 3.2(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution; and (iii) jurisdiction over all other actions and requested relief shall lie in any court of competent jurisdiction.

5. Notices.

All notices required pursuant to the terms of this Agreement shall be in writing, and served upon the following individuals in person, or at the following addresses or email addresses:

If to the Authorized Person:

(email address)

with a copy to

(email address)

If to PJM:

General Counsel
2750 Monroe Blvd.
Audubon, PA 19403
Vincent.Duane@pjm.com

If to the PJM Market Monitor:

Monitoring Analytics, LLC
[address and contact information]

6. Severability and Survival.

In the event any provision of this Agreement is determined to be unenforceable as a matter of law, the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Operating Agreement, the terms of the Operating Agreement shall in all events be controlling. The Authorized Person acknowledges that any and all obligations of the Authorized Person hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Person and their respective Authorized Commission.

7. Representations.

The undersigned represent and warrant that they are vested with all necessary corporate, statutory and/or regulatory authority to execute and deliver this Agreement, and to perform all of the obligations and duties contained herein.

8. Third Party Beneficiaries.

The Parties specifically agree and acknowledge that each Member as defined in the Operating Agreement is an intended third party beneficiary of this Agreement entitled to enforce its provisions.

9. Counterparts.

This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

10. Amendment.

This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

PJM INTERCONNECTION, L.L.C.

By:

Name:

Title:

AUTHORIZED PERSON

By:

Name:

Title:

**SCHEDULE 10A -
FORM OF CERTIFICATION**

This Certification (the “Certification”) is given this ____ day of _____, 200__, by _____, a _____ (the “Authorized Commission”), to and for the benefit of PJM Interconnection, LLC (“PJM”) and its Members. The Authorized Commission and PJM shall be referred to herein collectively as the “Parties”.

Whereas, the Authorized Commission has designated the individuals on attached Exhibit “A” (the “Authorized Persons”) to receive Confidential Information from PJM and/or the PJM Market Monitor, such Exhibit A to be updated from time to time, and

Whereas, as a condition precedent to the provision of Confidential Information to the Authorized Persons, the Authorized Commission is required to make certain representations and warranties to PJM, and

Whereas, PJM and/or the PJM Market Monitor will provide Confidential Information to the Authorized Commission subject to the terms of this Certification; and

Whereas, the Parties desire to set forth those representations and warranties herein.

Now, therefore, the Authorized Commission hereby makes the following representations and warranties, all of which shall be true and correct as of the date of execution of this Certification, and at all times thereafter, and with the express understanding that PJM, the PJM Market Monitor, and any Affected Member shall rely on each representation and/or warranty:

1. Definitions.

Terms contained, but not defined, herein shall have the definitions or meanings ascribed to such terms in the Operating Agreement.

2. Requisite Authority.

- a. The Authorized Commission hereby certifies that it has all necessary legal authority to execute, deliver, and perform the obligations in this Certification.
- b. The Authorized Persons have, through all necessary action of the Authorized Commission, been appointed and directed by the Authorized Commission to receive Confidential Information on the Authorized Commission's behalf and for its benefit.
- c. The Authorized Commission will, at all times after the provision of Confidential Information to the Authorized Persons, provide PJM with: (i) written notice of any changes in any Authorized Person's qualification as an Authorized Person within two (2) business days of such change; (ii) written confirmation to any inquiry by PJM regarding the status or identification of any specific Authorized Person within two (2) business days of such request, and (iii) periodic written updates, no less often than semi-annually, containing the names of all Authorized Persons appointed by the Authorized Commission.

3. Protection of Confidential Information.

- a. The Authorized Commission has adequate internal procedures, to protect against the release of any Confidential Information by the Authorized Persons or other employee or agent of the Authorized Commission, and the Authorized Commission and the Authorized Persons will strictly enforce and periodically review all such procedures.
- b. The Authorized Commission has legal authority to protect the confidentiality of Confidential Information from public release or disclosure and/or from release or disclosure to any other person or entity, either by the Authorized Commission or the Authorized Persons, as agents of the Authorized Commission.
- c. The Authorized Commission shall ensure that Confidential Information shall be maintained by, and accessible only to, the Authorized Persons.

4. Defense Against Requests for Disclosure.

The Authorized Commission shall, unless precluded from doing so by law, use reasonable efforts to defend against, and direct Authorized Persons to defend against, disclosure of any Confidential Information pursuant to any Third Party Request through all available legal process, including, but not limited to, obtaining any necessary protective orders. The Authorized Commission shall provide PJM and/or the PJM Market Monitor with prompt notice of any such Third Party Request or legal proceedings, and shall consult with PJM, the PJM Market Monitor, and/or any Affected Member in its efforts to deny the request or defend against such legal process. In the event a protective order or other remedy is denied, the Authorized Commission agrees to furnish only that portion of the Confidential Information which their legal counsel advises PJM and/or the PJM Market Monitor (and of which PJM and/or the PJM Market Monitor shall, in turn, advise any Affected Member) in writing is legally required to be furnished, and to exercise their best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

5. Use and Destruction of Confidential Information.

a. The Authorized Commission shall use, and allow the use of, the Confidential Information solely for the purpose of discharging its legal responsibility to examine and evaluate wholesale and retail electricity markets, operations, transmission planning and siting and generation planning and siting materially affecting retail customers within their respective State, and for no other purpose.

b. Upon completion of the inquiry or investigation referred to in any Information Request initiated by or on behalf of the Authorized Commission, or for any reason any Authorized Person is, or will no longer be an Authorized Person, the Authorized Commission will ensure that such Authorized Person either (a) returns the Confidential Information and all copies thereof to PJM and/or the PJM Market Monitor, or (b) provides a certification that the Authorized Person and/or the Authorized Commission (i) has destroyed all paper copies and deleted all electronic copies of the Confidential Information or (ii) that any information required by any provision of state law to be retained will continue to be protected from disclosure.

6. Notice of Disclosure of Confidential Information.

The State Commission shall promptly notify PJM and/or the PJM Market Monitor of any inadvertent or intentional release or possible release of the Confidential Information provided to any Authorized Person, and shall take all available steps to minimize any further release of Confidential Information and/or retrieve any Confidential Information that may have been released.

7. Release of Claims.

PJM and the PJM Market Monitor shall be expressly entitled to rely upon any Authorized Commission Certification, in providing Confidential Information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature due to the ineffectiveness or inaccuracies of such orders, or the inaccuracy of such certification of counsel, or PJM or the PJM Market Monitor's reliance on such orders, and the Authorized Commission hereby waives any such claim, now or in the future, whether known or unknown.

8. Ownership and Privilege.

Nothing in this Certification, or incident to the provision of Confidential Information to the Authorized Commission pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by PJM and/or the PJM Market Monitor, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of PJM, the PJM Market Monitor, and/or the Affected Member.

Executed, as of the date first set out above.

[Commission]

By: _____

Its: _____

SEE NEXT PAGE

**EXHIBIT A –
CERTIFICATION
LIST OF AUTHORIZED PERSONS**

<u>Name</u>	<u>Mailing Address</u>	<u>Email</u>	<u>Tel #</u>	<u>Scope and Duration of Authority</u>
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**SCHEDULE 11 -
ALLOCATION OF COSTS ASSOCIATED
WITH NERC PENALTY ASSESSMENTS**

References to section numbers in this Schedule 11 refer to sections of this Schedule 11, unless otherwise specified.

1.1 Purpose and Objectives.

Under the NERC Functional Model and the NERC Rules of Procedure, Registered Entities within a specific function may be assessed penalties by NERC for violations of NERC Reliability Standards. Pursuant to the terms and conditions of the PJM Governing Agreements, certain tasks associated with Reliability Standards compliance may be performed either by PJM Interconnection, L.L.C. ("PJM") and/or the Members even when they are not the Registered Entity. This Schedule furnishes a mechanism by which either PJM or a Member may directly allocate monetary penalties imposed by NERC on the Registered Entity to the entity or entities whose conduct is determined by NERC to have lead to a Reliability Standards violation. The purpose of this schedule is to allow for cost allocation; nothing in this schedule is intended to affect the obligations of the Registered Entity for compliance with NERC Reliability Standards.

1.2 [Reserved for Future Use]

1.3 Allocation of Costs When PJM is the Registered Entity

- (a) If NERC assesses a monetary penalty against PJM as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of a Member or Members contributed to the Reliability Standard violation(s) at issue, then PJM may directly allocate such penalty costs or a portion thereof to the Member or Members whose conduct contributed to the Reliability Standards violation(s), provided that all of the following conditions have been satisfied:
 - (1) The Member or Members received notice and an opportunity to fully participate in the underlying Compliance Monitoring and Enforcement Program proceeding;
 - (2) This Compliance Monitoring and Enforcement Program proceeding produced a finding, subsequently filed with FERC, that the Member contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and
 - (3) A root cause finding by NERC filed with the FERC identifying the Member's or Members' conduct as causing or contributing to the Reliability Standards violation charged against PJM as the Registered Entity.
- (b) PJM will notify the Member or Members found to have contributed to a violation, either in whole or in part, in the Compliance Monitoring and Enforcement Program. Such notification shall set forth in writing PJM's intent to invoke this Section 1.3 and directly assign the costs associated with a monetary penalty to the Member or Members and the underlying factual basis supporting a penalty cost assignment including the conduct contributing to the violation and the violations of the PJM Governing Agreement assigned tasks leading to the issuance of a penalty against the Registered Entity.
- (c) A failure by a Member or Members to participate in the Compliance Monitoring and Enforcement Program proceedings will not prevent PJM from directly assigning the costs associated with a monetary penalty to the responsible Member or Members provided all other conditions set forth herein have been satisfied.
- (d) PJM shall notify the Members or Members that PJM believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied.
- (e) Where the Regional Entity's and/or NERC's root cause finds that more than one party's conduct contributed to the Reliability Standards violation(s), PJM shall inform all involved Members and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with such NERC's root cause analysis.

- (f) Should Member or Members disagree with PJM regarding PJM's initial apportionment of the fault, the Dispute Resolution Procedures in Section 5 of the Operating Agreement shall not apply, but the parties' senior management shall first meet in an attempt to informally resolve the issue. If the disagreement cannot be resolved informally within ten (10) business days (or such other deadline as mutually agreed) then the following provisions shall apply:
 - (i) If an involved Member so elects, an informal non-binding proceeding shall be conducted within 30 days before a dispute resolution board consisting of officers of two (2) PJM Members who are not parties to the dispute and who are selected by a random drawing of names from the pool of available PJM Members and one (1) member of the PJM Board of Managers. Such dispute resolution board shall decide on the procedures to be used for the proceeding. The final recommendation of the dispute resolution board shall be made in private session within three (3) business days of the termination of the proceeding. The recommendation of the dispute resolution board shall be made by simple majority vote. The dispute resolution board may, but shall not be required to, provide a written basis for its recommendation; or
 - (ii) If an involved Member selects not to participate in the informal non-binding proceeding, then the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act. In the FERC proceeding, the involved Member shall request that FERC determine how the costs associated with the monetary penalty should be allocated. However, if there are multiple involved Members, and if any one of them desires a proceeding described in Section 1.3(f)(i) above, such proceeding shall first be conducted with respect to the Member(s) desiring such a proceeding.
- (g) If PJM and the involved Member(s) agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.
- (h) Notwithstanding anything to the contrary contained herein, if the Member or Members fail to pay their share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.3 (b) above, and the FERC issues a final order or orders which supports the NERC's root cause findings regarding the Member's or Members' conduct causing or contributing to the violation and PJM's initial determinations in paragraph 1.3 (f) above, such payment shall be due with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Registered Entity. Provided, however, if the Member or Members pays their share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.3 (b) above, and the FERC issues a final order or orders which does not support the NERC's root cause findings regarding the Member's or Members' conduct causing or

contributing to the violation and PJM's initial determinations in paragraph 1.3 (f) above, such payment shall be refunded in full with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Member or Members.

1.4 Allocation of Costs When a PJM Member is the Registered Entity

- (a) If NERC assesses a monetary penalty against a Member as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of PJM contributed to the Reliability Standard violation(s) at issue, then such Member may directly allocate such penalty costs or portion thereof to PJM to the extent PJM's conduct contributed to the Reliability Standards violation(s), provided that the following conditions have been satisfied:
 - (1) PJM received notice and an opportunity to fully participate in the underlying Compliance Monitoring and Enforcement Program proceeding;
 - (2) This Compliance Monitoring and Enforcement Program proceeding produced a finding, subsequently filed with FERC, that PJM contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and
 - (3) A root cause finding by NERC has been filed at the FERC identifying PJM's conduct as causing or contributing to the Reliability Standards violation charged against the Member as the Registered Entity.
- (b) The Member shall notify PJM if PJM is found to have contributed to a violation, either in whole or in part in the Compliance Monitoring and Enforcement Program. Such notification shall set forth in writing the Member's intent to invoke this Section 1.4 and directly assign the costs associated with a monetary penalty to PJM and the underlying factual basis supporting a penalty cost assignment including the conduct contributing to the violation and the violations of the PJM Governing Agreement assigned tasks leading to the issuance of a penalty against the Registered Entity.
- (c) A failure by PJM to participate in the Compliance Monitoring and Enforcement Program proceedings will not prevent the Member from directly assigning the costs associated with a monetary penalty to PJM provided all other conditions set forth herein have been satisfied.
- (d) The Member shall notify PJM that the Member believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied.
- (e) Where the Regional Entity's and/or NERC's root cause analysis finds more than one party's conduct contributed to the Reliability Standards violation(s), the Member shall inform PJM and make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to PJM's relative fault consistent with such root cause analysis.
- (f) Should PJM disagree with the Member regarding the Member's initial apportionment of the fault, the Dispute Resolution Procedures in Schedule 5 of the Operating Agreement shall not apply, but the parties' senior management shall first meet in an attempt to informally resolve the issue. If the disagreement cannot be resolved informally within

ten (10) business days (or other such deadline as mutually agreed) then the following provisions shall apply:

- i. If PJM so elects, an informal non-binding proceeding shall be conducted within 30 days before a dispute resolution board consisting of officers of two (2) PJM Members who are not parties to the dispute and who are selected by a random drawing of names from the pool of available PJM Members and one (1) member of the PJM Board of Managers. Such dispute resolution board shall decide on the procedures to be used for the proceeding. The final recommendation of the dispute resolution board shall be made in private session within three (3) business days of the termination of the proceeding. The recommendation of the dispute resolution board shall be made by simple majority vote. The dispute resolution board may, but shall not be required to, provide a written basis for its recommendation; or
 - ii. If PJM selects not to participate in the informal non-binding proceeding, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act. In the FERC proceeding, PJM shall request that the FERC determine how the costs associated with the monetary penalty should be assigned.
- (g) If the PJM and the involved Member(s) agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.
- (h) Notwithstanding anything to the contrary contained herein, if PJM fails to pay its share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.4 (b) above, and the FERC issues a final order or orders which supports the NERC's root cause findings regarding PJM's conduct causing or contributing to the violation and the Member's initial determinations in paragraph 1.4 (f) above, such payment shall be due with interest calculated at the FERC authorized rate from the date of payment of the penalty by the Registered Entity. Provided, however, if PJM pays its share of the Reliability Standard violation costs within 30 days of receipt of the notice required in paragraph 1.4 (b) above, and the FERC issues a final order or orders which does not support the NERC's root cause findings regarding PJM's conduct causing or contributing to the violation and the Member's initial determinations in paragraph 1.4 (f) above, such payment shall be refunded in full with interest calculated at the FERC authorized rate from the date of payment of the penalty by PJM.

1.5

Any and all costs associated with the imposition of NERC Reliability Standards penalties that may be assessed against PJM either directly by NERC or allocated by a Member or Members under this Schedule shall be (i) paid by PJM notwithstanding the limitation of liability provisions in Section 16 of the Operating Agreement; and (ii) recovered as set forth in Schedule 9 of the PJM Tariff, or as otherwise approved by the FERC.

SCHEDULE 12 - PJM MEMBER LIST

A2A Energy International, LLC
Abest Power & Gas, LLC
AC Energy, LLC
Acciona Energy North America Corporation (AENAC)
Achieving Equilibrium LLC
AEP Appalachian Transmission Company, Inc.
AEP Energy Partners, Inc.
AEP Energy, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP Retail Energy Partners, LLC
AEP West Virginia Transmission Company, Inc.
AES Beaver Valley LLC
AES Energy Storage, LLC
AES ES Holdings, LLC
Aesir Power, LLC
AES Laurel Mountain, LLC
AES Ohio Generation, LLC
A.F. Mensah Inc.
Agera Energy LLC
Aggressive Energy LLC
Agway Energy Services, LLC
Air Liquide Industrial US, LP
Air Products & Chemicals, Inc.
AK Steel Corporation
Alabama Power Company
Alegria Fund, LP
Algonquin Energy Services, Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, LLC
ALLETE, Inc. d/b/a Minnesota Power
Alliant Energy Corporate Services, Inc.
Alliant Energy Resources, LLC
Alpaca Energy LLC
Alpha Gas and Electric, LLC
Altus Power America, Inc.
Amazon Energy LLC
Ambit Northeast, LLC
American Illuminating Company, LLC
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of Ohio, LLC

American Power & Gas of Pennsylvania, LLC
American Power & Gas of NJ, LLC
American Power Partners, LLC
American PowerNet Management, L.P.
American Transmission Company, LLC
American Transmission Systems Inc.
Amerigreen Energy, Inc.
Ames Energy, LLC
Amity Energy LLC
Anahau Energy, LLC
Anbaric Northeast Transmission Development Company, LLC
AP Gas & Electric (IL), LLC
AP Gas & Electric (MD), LLC
AP Gas & Electric (OH), LLC
AP Gas and Electric (NJ), LLC
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Appalachian Power Company
Appian Way Energy Partners MidAtlantic, LLC
Apple Group LLC
APX, Inc.
Aquenergy Systems Inc.
ArcelorMittal USA, LLC
ArcLight Energy Marketing, L.L.C.
Armada Power, LLC
Armenia Mountain Wind, LLC
Arrow Energy RRH, LLC
Aspirity Energy, LLC
Associated Electric Cooperative, Inc.
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
Atlantic Grid Operations A, LLC
ATNV Energy, LP
Automated Algorithms, LLC
Avangrid Renewables, LLC
AXPO U.S. LLC
Baker Boy, LLC
Baltimore Gas and Electric Company
Baltimore Power Company LLC
Barclays Capital Services, Inc
Bargain Energy, LLC
Bartram Lane, LLC
Battery Utility of Ohio, LLC
Bayles Energy LLC
Bayonne Plant Holding, L.L.C.

Bazinga, LLC
BBPC LLC d/b/a/ Great Eastern Energy
Beacon Power, LLC
Bear Island Paper WB LLC
Beaver Dam Energy LLC
Beech Ridge Energy LLC
Beech Ridge Energy Storage LLC
Berks Hollow Energy Associates, LLC
Bernards Solar, LLC
Big Bend Trading, LLC
Big Rivers Electric Corporation
Big Sandy Peaker Plant, LLC
Big Savage, LLC
Big Sky Wind, LLC
Biogas Energy Solutions LLC
BioUrja Power, LLC
Birdsboro Power LLC
Bishop Hill Energy LLC
BIF II Safe Harbor Holding LLC
BIF III Holtwood LLC
BITH Solar I, LLC
BJ Energy, LLC
Black Oak Capital, LLC
Black Oak Energy, LLC
Blackout Power Trading Inc.
Blackstone Wind Farm II, LLC
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Bluegrass Generating Company, LLC
BlueRock Energy, Inc.
BNP Paribas Energy Trading GP
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Madison, New Jersey
Borough of Milltown
Borough of Mont Alto
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights
Borough of South River, New Jersey
Boston Energy Group, Inc.
Boston Energy Trading and Marketing LLC
Bounce Energy PA, LLC

BP Energy Company
Brandon Shores LLC
Brick Standard LLC
Brighten Energy, LLC
Brookfield Energy Marketing, LP
Brookfield Power Piney & Deep Creek LLC
Brookfield Renewable Energy Marketing US LLC
Bruce Power Inc.
Brunner Island, LLC
Buckeye Power, Inc.
C.P. Crane LLC
Cahaya Power Marketing LLC
Calpine Bethlehem, LLC
Calpine Energy Services, L.P.
Calpine Mid Atlantic Marketing, LLC
Calvert Cliffs Nuclear Power Plant, LLC
Cambria Cogen Company
Camden Plant Holding, L.L.C.
Camp Grove Wind Farm, LLC
Canadian Wood Products – Montreal, Inc. dba CWP Energy
Capacity Markets Partners, LLC
Cape May County Municipal Utilities Authority
Capital Energy LLC
Cargill Power Markets, LLC
Carroll County Energy LLC
Casterbridge Advisory, L.L.C.
Castleton Commodities Merchant Trading L.P.
CenStar Energy Corp.
Central Transmission, LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
CES Retail Energy Supply, LLC
Champion Energy Marketing LLC
Champion Energy Services, LLC
Champion Energy, LLC
Chesapeake Trading Group, LLC
Chesapeake Transmission LLC
Chief Conemaugh Power, LLC
Chief Keystone Power, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Church Hill Solar Farm, LLC
Cincinnati Bell Energy, LLC
Cinnamon Bay, LLC
Citigroup Energy Inc.
Citizens' Electric Company of Lewisburg, PA
City of Batavia, Illinois

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Geneva (The)
City of Hamilton
City of New Martinsville – WV
City of Philippi – West VA
City of Rochelle
CleanChoice Energy, Inc.
Clean Energy Future – Lordstown, LLC
CleanLight Power + Energy, LLC
Clear Power LLC
Clearview Electric, Inc.
Cleveland Electric Illuminating Company
Climaton Research Company
CMS Energy Resource Management Company
Coaltrain Energy LP
Coastal Strategies, LLC
Coastal Wind and Solar Resources, LLC
Cogen Technologies Linden Venture, L.P.
Cogentrix Virginia Financing Holding Company, LLC
Cognovi Analytics, LLC
Collegiate Clean Energy, LLC
Commerce Energy Inc.
Commonwealth Chesapeake Company, LLC
Commonwealth Edison Company
Community Energy, Inc.
Comperio Energy LLC dba ClearChoice Energy
Conch Energy Trading, LLC
ConocoPhillips Company
Consolidated Edison Company of New York, Inc.
Consolidated Edison Energy, Inc.
Consolidated Edison Solutions, Inc.
Constellation Energy Power Choice, LLC
Constellation Energy Services, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, LLC
Consumers Energy Company
Cordova Energy Company LLC
Corona Power LLC
County of Frederick, VA
Covanta Delaware Valley, L.P.
Covanta Energy Group, LLC
Covanta Essex Company
Covanta Union, LLC
CP Energy Marketing (US) Inc.
CPV MARYLAND, LLC
CPV Shore, LLC

Credit Suisse (USA), Inc.
Crescent Ridge LLC
Crete Energy Venture, LLC
Cube Hydro Partners, LLC
Cumulus Master Fund
Current Power & Gas Inc.
Customized Energy Solutions, Ltd.
Cygnus Energy Futures, LLC
Darby Energy, LLLP
Dart Container Corporation of Pennsylvania
Dayton Power & Light Company (The)
DC Energy LLC
DC Energy Mid-Atlantic, LLC
DCO Energy, LLC
Decatur Energy Center, LLC
DEL LIGHT INC.
Delaware Division of the Public Advocate
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Demansys Energy, LLC
Denver Energy, LLC
Devonshire Energy, LLC
Diamond State Generation Partners, LLC
Direct Energy Business, LLC
Direct Energy Business Marketing, LLC
Direct Energy Services, LLC
Divine Power, Inc.
Dominion Energy Marketing, Inc.
Domtar Paper Company, LLC
Doswell Limited Partnership
Downes Associates, Inc.
DPL Energy Resources, LLC
DTE Energy Trading, Inc.
Dufossat Capital I, LLC
Duke Energy Business Services, LLC
Duke Energy Carolinas, LLC
Duke Energy Commercial Enterprises, Inc.
Duke Energy Florida, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Progress, LLC
Duke Energy Renewable Services, LLC
Duquesne Conemaugh LLC
Duquesne Keystone LLC
Duquesne Light Company
Duquesne Light Energy, LLC

Duquesne Power LLC
Dynasty Energy Group LLC
Dynasty North America Holdings Inc.
Dynasty Power Inc.
Dynergy Energy Services, LLC
Dynergy Kendall Energy, LLC
Dynergy Marketing and Trade, LLC
Dynergy Power Marketing, LLC
Dyon, LLC
E Minus LLC
E.ON Climate & Renewables North America Inc.
Eagle Point Power Generation LLC
Eagle's View Multi-Strategy, LLC
Earth Networks, Inc.
East Coast Power & Gas of New Jersey, LLC
East Coast Power Linden Holdings, L.L.C.
Eastern Generation, LLC
Eastern Shore Solar LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
Ebensburg Power Company
Ebrfuel, LLC
eCap Network, LLC
Ecesis LLC
EcoGrove Wind, LLC
EDF Trading North America, LLC
Edison Transmission, LLC
EDP Energy Services, LLC
EDP Renewables North America, LLC
EF Kenilworth LLC
EFS Parlin Holdings, LLC
El Paso Marketing, L.P.
Elgin Energy Center, LLC
Eligo Energy, LLC
Elliot Bay Energy Trading, LLC
Elmagin Power Fund LLC
Elmwood Park Power, LLC
Elwood Energy LLC
EMC Development Company, Inc.
Emera Energy Services, Inc.
Emporia Hydropower Limited Partnership
ENBALA Power Networks, Inc.
Endurance Energy Midwest LLC
Energetix, Inc.
Energy America, LLC
Energy Answers Baltimore, LLC

Energy Authority, Inc. (The)
Energy Consulting Services, LLC
Energy Cooperative Association of Pennsylvania
Energy Cooperative of America, Inc.
Energy Limited Inc.
Energy Plus Holdings LLC
Energy Power Investment Company, LLC
Energy Service Providers, Inc.
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
Energy.me Midwest llc d/b/a energy.me
Energys VM Gestion de Energia S.L.U.
EnergyConnect, Inc.
EnerNOC, Inc.
EnerPenn USA, LLC
Enerwise Global Technologies, Inc.
Engelhart CTP (US) LLC
ENGIE Resources LLC
ENGIE Retail, LLC
Entegra Power Services LLC
Entrust Energy East, Inc.
EPP Renewable Energy, LLC
Essential Power OPP, LLC
Essential Power Rock Springs, LLC
Essential Power, LLC
ETC Endure Energy L.L.C.
Evergreen Community Power
Evergreen Gas & Electric, LLC
EverPower Commercial Services, LLC
Everyday Energy, LLC
Exel Power Sources, LLC
Exelon Business Services Company, LLC
Exelon Generation Company, LLC
Exion Energy Inc.
Falcon Energy, LLC
Fantods LLC
Fermata, LLC
First Point Power, LLC
FirstEnergy Solutions Corp.
Florey Knob Energy LLC
Florida Power & Light Company
Forest Investment Group, LLC
Forked River Power LLC
Fowler Ridge II Wind Farm LLC
Fowler Ridge III Wind Farm LLC
Fowler Ridge IV Wind Farm LLC

Fowler Ridge Wind Farm LLC
FPL Energy Marcus Hook LP
Franklin Power LLC
Freepoint Commodities LLC
Freepoint Energy Solutions LLC
Frontier Utilities Northeast, LLC
Future Power PA LLC
G&G Energy, Inc.
G&S Wantage Solar, LLC
Gallus Capital LLC
Galt Power, Inc.
Gateway Energy Services Corporation
GBE Energy Marketing Inc.
GDF SUEZ Energy Marketing NA, Inc.
GDF SUEZ Energy Resources NA, Inc.
Gen IV Investment Opportunities, LLC
Genbright LLC
GenOn Energy Management, LLC
Gen Ops, LLC
Georgia Power Company
Gerdau Ameristeel Energy, Inc
Geronimo Energy Holdings, LLC
Grain Belt Express Clean Line LLC
Grand Ridge Energy II LLC
Grand Ridge Energy III LLC
Grand Ridge Energy IV LLC
Grand Ridge Energy LLC
Grand Ridge Energy V LLC
Grand Ridge Energy Storage, LLC
Granger Energy of Honey Brook, LLC
Grays Ferry Cogeneration Partnership
Great American Power, LLC
Great Barrington Energy Fund LP
Great Bay Energy I, LLC
Great Bay Energy III, LLC
Great Falls Hydroelectric Company, Limited Partnership
GreenHat Energy, LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Greene Energy, LLC
greeNEWit, LLC
GRG ENERGY LLC
Gridforce Energy Management, LLC
GSG, LLC
GSG 6, LLC
Gulf Power Company

Guttman Energy, Inc.
Guzman Energy LLC
H.A. Wagner LLC
H.Q. Energy Services (U.S.), Inc.
Hagerstown Light Department
Half Moon Ventures, LLC
Handsome Lake Energy, LLC
Harborside Energy, LLC
Harrison REA, Inc. – Clarksburg, WV
Hartree Partners, LP
Hawks Nest Hydro LLC
Hazle Spindle, LLC
Hazleton Generation LLC
Headwaters Wind Farm LLC
Hemsworth Capital LP
Hemsworth Capital Midwest LP
Hexis Energy Trading, LLC
Hickory Run Energy, LLC
Highland North LLC
High Resolution Energy, LLC
High Resolution Energy VT Fund I, LP
HIKO Energy, LLC
Hill Energy Resource & Services, LLC
Hill Top Energy Center, LLC
Holcim (US), Inc.
Holocene Finance, LLC
Holtwood, LLC
Homer City Generation, LP
Hoosier Energy REC, Inc.
Hop Bottom Energy LLC
Horizon Energy Investments, Inc.
Horizon Power and Light, LLC
H-P Energy Resources, LLC
HSBC Technology & Services (USA), Inc.
Hudson Energy Services, LLC
Hudson Transmission Partners, LLC
Icetec.com, Inc.
Icetec Energy Services, Inc.
IDT Energy, Inc.
Illinois Citizens Utility Board
Illinois Municipal Electric Agency
Illinois Power Marketing Company
IMG Midstream LLC
Indeck Energy Services, Inc.
Indeck Niles, LLC
Independence Energy Group, LLC

Independent Energy Consultants, Inc.
Indiana Michigan Power Company
Indiana Municipal Power Agency
Indiana Office of Utility Consumer Counselor (IN OUCC)
Industrial Energy Users-Ohio
Inertia Power I, LLC
Ingenco Holdings, LLC
Ingenco Wholesale Power, LLC
Innovari Market Solutions LLC
Innovation Tap LLC d/b/a Innotap
Innoventive Power LLC
Inspire Energy Holdings, LLC
Intelligent Generation, LLC
International Paper Company
Interstate Gas Supply, Inc.
Interstate Power and Light Company
Invenergy LLC
Invenergy Nelson LLC
Ioway Energy, LLC
IPKeys Power Partners LLC
Iron Energy LLC
iSigma, Inc.
ITC Interconnection LLC
ITC Mid-Atlantic Development LLC
J. Aron & Company
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
James River Genco, LLC
Jane Street Energy Trading, LLC
Jersey Central Power & Light Company
Jersey Green Energy, LLC
Jersey-Atlantic Wind, LLC
Joliet Battery Storage LLC
Josco Energy USA, LLC
JP Morgan Ventures Energy Corporation
JPTC, LLC
Kansas City Power & Light Company
KASS Commodities, LLC
KDC Solar Green Power LLC
Kentucky Power Company
KeyTex Energy LLC
KeyTex Energy Solutions LLC
KFW Energy, LLC
Kimberly-Clark Corporation
Kincaid Generation, LLC
Kingsport Power Company
Kiyoshi Technologies, LLC

KMC Thermo, LLC
Koch Energy Services, LLC
KOREnergy, Ltd.
Krayn Wind LLC
Kuehne Chemical Company, Inc.
Kupper Engineering, Inc.
L&P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Lackawanna Energy Center LLC
Lancaster County Solid Waste Management Authority
Land O'Lakes, Inc.
Lantar Energy LLC
LCG Consulting
Lee River Proprietary Strategies, Inc.
Leeward Asset Management, LLC
Legacy Energy Group, LLC (The)
Lehigh Portland Cement Company
Lehman Brothers Commodity Services, Inc.
Letterkenny Industrial Development Authority – PA
Levelsail Trading, LLC
Liberty Electric Power, LLC
Liberty Hill Power LLC
Liberty Power Corp., L.L.C.
Liberty Power Delaware, LLC
Liberty Power District of Columbia LLC
Liberty Power Holdings LLC
Liberty Power Maryland, LLC
LifeEnergy, LLC
Lincoln Generating Facility, LLC
Linde Energy Services, Inc.
Linde, LLC
Linden VFT LLC
Links EP LLC
LM Power, LLC
Long Island Lighting Company d/b/a LIPA
Longview Power, LLC
Louisville Gas and Electric Company/Kentucky Utilities Company
Lower Electric, LLC
Lower Mount Bethel Energy, LLC
LQA, LLC
LSP University Park, LLC
LTSTE Investments, LLC
Lykins Oil Company d/b/a Lykins Energy Solutions
Mac Trading, Inc.
Macquarie Energy, LLC
Madison Gas and Electric Co.
MAG Energy Solution, Inc.

Mahoning Creek Hydroelectric Company, LLC
Major Energy Electric Services, LLC
Manatee Transmission LLC
Mansfield Power and Gas, LLC
Maple Analytics, LLC
Marathon Power LLC
Marina Energy, LLC
Martins Creek, LLC
Maryland Office of People's Counsel
Mattawoman Energy, LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm II, LLC
Meadow Lake Wind Farm III, LLC
Meadow Lake Wind Farm IV, LLC
Meadow Lake Wind Farm, LLC
MeadWestvaco Corporation
Median Energy Corp.
Mega Energy Holdings, LLC
MEG Generating Company, LLC
Mehoopany Wind Energy LLC
Mendota Hills, LLC
Mercuria Energy America, Inc.
Mercuria SJAK Trading, LLC
Merrill Lynch Commodities, Inc.
MET MA LLC
Metropolitan Edison Company
Miami Valley Lighting, LLC
Michigan Department of Attorney General, Environment, Natural Resources & Agriculture
Division
Michigan Public Power Agency
Microsoft Corporation
MidAmerican Energy Company
MidAmerican Energy Services, LLC
MidAtlantic Power Partners, LLC
Mid-Atlantic Renewable Energy Coalition
Middlesex County Utilities Authorities
Middlesex Energy Center, LLC
Midwest Energy Trading East LLC
Midwest Generation, LLC
Milan Energy LLC
Milford Solar LLC
Mint Energy, LLC
Mississippi Power Company
Monmouth Energy, Inc.
Monongahela Power Company d/b/a Allegheny Power
Monterey MA, LLC

Monterey MAF, LLC
Montour, LLC
Morgan Stanley Capital Group, Inc.
Morgan Stanley Services Group Inc.
Morgans Corner Solar Energy LLC
Morris Cogeneration, L.L.C
Mosaic Power, LLC
Moundsville Power, LLC
Moxie Freedom LLC
MP2 Energy NE, LLC
MP2 Energy, LLC
MPCF I, LLC
MPower Energy NJ LLC
Mt. Carmel Cogeneration Inc.
Nalcor Energy Marketing Corporation
NATGASCO d/b/a/ Supreme Energy, Inc.
National Gas & Electric, LLC
Natural Gas Exchange Inc.
Nautilus Solar Energy, LLC
NedPower Mount Storm, LLC
NEPM II, LLC
Neptune Regional Transmission System, LLC
NERC-Middlesex Solar I, LLC
Newark Energy Center, LLC
New Covert Generating Company, LLC
New Jersey Division of the Ratepayer Advocate
New York Power Authority
New York State Electric & Gas Corporation
Newark Bay Cogeneration Partnership, L.P.
NextEra Energy Power Marketing, LLC
NextEra Energy Services Illinois, LLC
NextEra Energy Services New Jersey, LLC
NextEra Energy Transmission, LLC
Nittany Energy, LLC
NJ Brothers Capital Limited
NJR Clean Energy Ventures Corporation
NJR Clean Energy Ventures II Corporation
Noble Americas Energy Solutions, LLC
Noble Americas Gas & Power Corp.
Nordic Energy Services LLC
North American Natural Resources – SBL, LLC
North American Power and Gas, LLC
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
North Hanover Solar W2-082, LLC
Northampton Generating Company, L.P.

Northeast Maryland Waste Disposal Authority
Northeast Transmission Development, LLC
Northeastern REMC
Northern Illinois Municipal Power Agency
Northern Indiana Public Service Company
Northern States Power Company
Northern Virginia Electric Cooperative - NOVEC
NorthPoint Energy Solutions, Inc.
Northstar Trading Ltd.
NRG Curtailment Solutions, Inc.
NRG Potomac River LLC
NRG Power Marketing, LLC
NRG Power Midwest LP
NRGStream LLC
NTE Carolinas, LLC
NTE Ohio, LLC
NuEnergen, LLC
NYSEG Solutions, Inc.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Oceanside Power, LLC
Office of the Attorney General, Kentucky
Office of the People's Counsel for the District of Columbia
Ohio Consumer's Counsel
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corporation
OhmConnect, Inc.
Old Dominion Electric Cooperative
Olympus Power, LLC
Ontario Power Generation Energy Trading, Inc.
Ontario Power Generation Inc.
Ontelaunee Power Operating Company
Oregon Clean Energy, LLC
Orthogonal Energy, LLC
Osaka Gas USA Corporation
Owensboro Municipal Utilities
Oxbow Creek Energy LLC
Oxford Energy Services, LLC
Ozark International, Inc.
P.H. Glatfelter Company
Pacific Summit Energy LLC
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC

Palmco Power NJ, LLC
Palmco Power OH, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Panda Hummel Station LLC
Panda Liberty LLC
Panda Patriot LLC
Panda Stonewall LLC
Panther Creek Power Operating, LLC
Park Power LLC
Parma Energy LLC
PATH Allegheny Transmission Company, LLC
PATH West Virginia Transmission Company, LLC
Patton Wind Farm, LLC
Paulding Wind Farm II LLC
Paulding Wind Farm III LLC
PBF Power Marketing, LLC
PECO Energy Company
Pedricktown Cogeneration Company LP
PEI Power Corporation
PEI Power II, LLC
Peninsula Power, LLC
Penncat Corporation
Pennsylvania Electric Company
Pennsylvania Office of Consumer Advocate
Pennsylvania Power Company
Pennsylvania Renewable Resources, Associates
Pentacles Electric, LLLP
Pepco Energy Services, Inc.
Perigee Energy, LLC
PG Energy Services Inc. d/b/a/ PG Energy Power Plus
Philadelphia Energy Solutions Refining and Marketing LLC
Piedmont Energy Fund, L.P.
Pine Hill Energy LLC
Pinnacle Power LLC
PJLB LLC
PJS Capital, LLC
Plain Rights, LLC
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plant-E Corp.
Plutus Trading Company, LP
Portsmouth Genco, LLC
Potomac Edison Company (The) d/b/a Allegheny Power
Potomac Electric Power Company

Power Dave Fund LLC
Power Engineers, Incorporated
Power Generation Services, Inc.
Powerex Corporation
Power Supply Services, LLC
PPGI Fund A/B Development, LLC
PPL Electric Utilities Corporation dba PPL Utilities
Prairieland Energy, Inc.
Praxair, Inc.
Precept Power LLC
Procter & Gamble Paper Products Company (The)
Property Endeavors LLC
Providence Heights Wind, LLC
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
PSEG Fossil LLC
PSEG Nuclear LLC
Public Power, LLC(CT)
Public Service Electric and Gas Company
Public Staff – North Carolina Utilities Commission
Pure Energy, Inc.
Quasar Energy Group, LLC
Raiden Commodities LP
Rainbow Energy Marketing Corporation
Rainbow Energy Ventures LLC
Raven Power Marketing LLC
RBC Energy Services LP
RC Cape May Holdings, LLC
Realgy, LLC
Recurrent Energy, LLC
Red Glen Energy LLC
Red Oak Power, LLC
Red Wolf Energy Trading, LLC
Red Wolf PT, LLC
Reliant Energy Northeast, LLC
Renaissance Power, LLC
Renaissance Power & Gas, Inc.
Renergy Inc.
Repsol Energy North America Corporation
RES America Developments Inc.
ResCom Energy, LLC
Residents Energy, L.L.C.
Respond Power, LLC
Richland-Stryker Generation LLC
RI-Corp. Development, Inc.

Ringer Hill Wind, LLC
Riverside Generating Company, L.L.C.
RJUMR Energy Partners Corp.
Robinson Power Company, LLC
Rochester Gas and Electric Corporation
Rock Island Clean Line LLC
Rockland Electric Company
Rocky Road Power, LLC
Rolling Hills Generating, L.L.C.
Roth Rock Wind Farm, LLC
Roundtop Energy LLC
Royal Bank of Canada
RPA Energy, Inc.
R.R. Donnelley & Sons Company
RRI Energy Services, LLC
RRI Energy Solutions East, LLC
RTP Controls, Inc
Rushmore Energy, LLC (new).
S.J. Energy Partners, Inc.
Safe Harbor Water Power Corporation
Safeway Inc.
Santanna Energy Services
Sapphire Power Marketing LLC
Saracen Energy East LP
Saracen Energy Midwest LP
Saracen Energy West LP
Saracen Power LP
Saugatuck River Power Trading LLC
Schuylkill Energy Resources, Inc.
Scrubgrass Generating Company, L.P.
Scylla Energy LLC
SESCO ENTERPRISES LLC
Seven Islands Environmental Solutions, LLC
Severn River Power LLC
Seward Generation, LLC
SFE Energy Pennsylvania, Inc.
SFE Energy, Inc.
SFE Energy NJ, Inc.
Shell Energy North America (U.S.), L.P.
Shipley Choice LLC
Siemens Industry, Inc.
SmartEnergy Holdings, LLC
SNC-Lavalin Constructors, Inc.
Solea Energy, LLC
Solios Power Mid-Atlantic Trading, LLC
Solios Power Mid-Atlantic Virtual LLC

Source Power & Gas LLC
South Carolina Electric & Gas Company
South Field Energy LLC
South Jersey Energy Company
Southard Energy Partners LLC
Southeastern Chester County Refuse Authority
Southeastern Power Administration
Southern Indian Gas and Electric Company d/b/a Vectren Power Supply Inc.
Southern Maryland Electric Cooperative, Inc.
Southern Power Company
Southland Industries
Spark Energy, LLC
Sperian Energy Corp
Spring Energy RRH, LLC dba Spring Power & Gas
Star Energy Partners LLC
Starion Energy PA, Inc.
STATARB INVESTMENTS LLC
St. Joseph Energy Center, LLC
Stoney Creek Wind Farm, LLC
Strategic Transmission LLC
Stream Energy Columbia, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Strom Power, LLC
Suffolk Fund LLC
Summer Energy of Ohio LLC
SunCoke Energy, Inc
Sunico LLC
Susquehanna Nuclear, LLC
Sustaining Power Solutions LLC
Switch Energy, LLC
Syncarpha Solar, LLC
Talen Energy Marketing, LLC
Tangent Energy Solutions, Inc.
TAQA Gen X LLC
Targray Americas Inc.
Tatanka Wind Power, LLC
TEC Energy Inc.
TEC Trading, Inc.
Tenaska Pennsylvania Partners, LLC
Tenaska Power Management, LLC
Tenaska Power Services Co.
Tenaska Virginia Partners, L.P.
Tennessee Valley Authority (The)
TERM Power & Gas, LLC

Texas Retail Energy, LLC
The Hartz Group
The Highlands Energy Group, LLC
The Mobility House, LLC
THG Energy Solutions, LLC
Thurmont Municipal Light Company
Tilton Energy, LLC
Titan Gas and Power
Toledo Edison Company (The)
Torofino Trading, LLC
Town of Berlin, Maryland
Town of Front Royal, Virginia
Town of Williamsport
Town Square Energy East, LLC
TrailStone Power, LLC
Trans-Allegheny Interstate Line Company
TransAlta Energy Marketing (US) Inc.
TransCanada Power Marketing, Ltd.
TranSource, LLC
Transource Energy, LLC
Transource West Virginia, LLC
Tri-County Rural Electric Cooperative, Inc.
Trident Retail Energy, LLC
TriEagle Energy, LP
Triolith Energy Fund, LP
TrueLight Commodities, LLC
TrueLight Energy Fund, LP
Trumpet Trading Group, LLC
Trustees of the University of Pennsylvania
Twin Eagle Resource Management, LLC
Tyne Hill Investments LP
UGI Development Company
UGI Energy Services, LLC
UGI Utilities, Inc.
Uncia Energy LP – Series B
Union Electric Company d/b/a Ameren Missouri
Union Power Partners, L.P.
Uniper Global Commodities North America, LLC
University Park Energy, LLC
Valent Energy, LLC
VCharge, Inc.
VECO Power Trading, LLC
Vel Energy, LP
Velocity American Energy Master I, LP
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC

Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility
Virginia Division of Consumer Counsel
Virginia Electric and Power Company
Virginia State Corporation Commission
Viridian Energy PA, LLC
Viridity Energy, Inc.
Virtual Power Hedging, LLC
Vitol, Inc.
Voltus, Inc.
Wabash Valley Power Association, Inc.
Volunteer Energy Services, Inc.
Wellsboro Electric Company
West Chicago Battery Storage LLC
West Deptford Energy II, LLC
West Deptford Energy, LLC
West Oaks Energy, L.P.
West Penn Power Company d/b/a Allegheny Power
West Virginia Consumer Advocate Division
Westar Energy, Inc.
Western Reserve Energy Services, LLC
Westmoreland Partners
Weston Solutions, Inc.
Westwood Generation, LLC
WGL Energy Services, Inc.
Wheelabrator Baltimore, L.P.
Wheelabrator Falls Inc.
Wheelabrator Frackville Energy Co Inc.
Wheelabrator Gloucester Company, L.P.
Wheelabrator Portsmouth, Inc.
Wheeling Power Company
Wildcat Wind Farm I, LLC
Willey Battery Utility, LLC
Wisconsin Electric Power Company
Wisconsin Power and Light Company
WM Renewable Energy, LLC
Wolf Hills Energy, LLC
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Wolverine Trading, LLC
WPPI Energy
Wyandot Solar LLC
Wylan Energy, L.L.C.
XO Energy CAL2 LP

XO Energy MA, LP
XO Energy MA2, LP
XO Energy NY2 LP
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
XOOM Energy Washington D.C., LLC
Xoom Energy, LLC
Yasmin Partners LLC
Yes Energy LLC
York County Solid Waste and Refuse Authority
York Generation Company LLC
York Haven Power Company, LLC
ZF Energy Development, LLC
Zongyi Solar America Co. Ltd.

Schedule 13

Rates, Terms, and Conditions of Service for PJM Settlement, Inc.

In accordance with the order of the Commission, dated September 3, 2010, in Docket No. ER10-1196-000, this Schedule 13 establishes as a shared tariff the rates, terms, and conditions of PJMSettlement services as set forth below.

- a) Under the PJM Tariff and this Agreement, PJM administers the provision of transmission service and associated ancillary services to customers and operates and administers various centralized electric power and energy markets.
- b) Under the PJM Tariff and this Agreement, PJMSettlement is the entity that (i) contracts with customers and conducts financial settlements regarding the use of the transmission capacity of the Transmission System that PJM, as the Transmission Provider, administers under the PJM Tariff and this Agreement; (ii) is the Counterparty with respect to the agreements and “pool” transactions in the centralized markets that PJM, as the Transmission Provider, administers under the PJM Tariff and this Agreement; and (iii) is the Counterparty to Financial Transmission Rights and Auction Revenue Rights instruments held by a Market Participant.
- c) In accordance with Section 3.3 of this Agreement, unless otherwise expressly stated in the PJM Tariff or this Agreement, PJMSettlement is the Counterparty to the customers purchasing Transmission Service and Network Integration Transmission Service, and to the other transactions with customers and other entities under the PJM Tariff or this Agreement. Accordingly, all rates, terms, and conditions of Transmission Service, Network Integration Transmission Service, and other transactions with entities under this Agreement, set forth throughout this Agreement, shall constitute rates, terms, and conditions of PJMSettlement service.
- d) Each seller shall be deemed to warrant that it holds good title to the products that are the subject of transactions it undertakes with PJMSettlement as a buyer. In accordance with and consistent with this warranty, PJMSettlement in turn warrants that it holds good title to the products that are the subject of transactions it undertakes with each buyer. The warranties set forth in this paragraph are provided only in connection with the requirements established by the FERC for PJMSettlement to serve as a Counterparty. Accordingly, any enforcement of, or challenge to, the warranties set forth in this paragraph shall be heard exclusively before the FERC. This paragraph is not intended to create independent rights or obligations for any party under the Uniform Commercial Code or common law that might be enforceable in federal or state courts or in any forum other than FERC.
- e) In accordance with section 3.3 of this Agreement, PJMSettlement shall not be the contracting party to other non-transmission transactions that are (1) bilateral transactions between market participants reported to the Transmission Provider, and (2) self-supplied or self-scheduled transactions reported to the Transmission Provider.

- f) In accordance with section 3.3 of this Agreement, PJMSettlement shall not be the Counterparty with respect to agreements and transactions regarding the Transmission Provider's administration of Parts IV and VI, Schedules 1, 9 (excluding Schedule 9-PJMSettlement), 10-Michigan-Ontario Interface, 10-NERC, 10-RFC, 14, 16, 16-A, and 17 of the PJM Tariff.
- g) The costs of services provided by PJMSettlement for the benefit of Market Participants and Transmission Customers shall be collected by PJMSettlement through the charge set forth in Schedule 9-PJMSettlement of the PJM Tariff.
- h) Billing and payment provisions applicable to PJMSettlement are set forth in section 7 of the PJM Tariff and section 14 and 14B of this Agreement.

**RESOLUTION TO AMEND THE
PROCEDURES REQUIRING THE RETENTION OF
AN INDEPENDENT CONSULTANT TO
PROPOSE A LIST OF CANDIDATES
FOR THE BOARD OF MANAGERS ELECTION FOR 2001**

1. For the election of Board Members at the Annual Meeting in 2001, an independent consultant to prepare a list of persons qualified and willing to serve on the PJM Board in accordance with Section 7.1 of the Operating Agreement shall not be required.
2. Section 7.1 of the Operating Agreement shall be deemed to be amended by the foregoing for the election at the Annual Meeting in 2001.
3. PJM shall make the necessary regulatory filings with the Federal Energy Regulatory Commission to implement the foregoing.