Definitions

(Clean Format)

Definitions A - B

10-minute Ramp and Uncertainty Reserve Down:

"10-minute Ramp and Uncertainty Reserve Down" shall mean the reserve capability of generation resources corresponding to the energy that can be decreased or Economic Load Response Participant resources whose demand can be increased within 10 minutes and is provided by equipment that is electrically synchronized to the Transmission System and dispatchable by the Office of the Interconnection through economic dispatch.

10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price:

"10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price" shall mean the locational clearing price for 10-minute Ramp and Uncertainty Reserve Down at the location the 10-minute Ramp and Uncertainty Reserve Down is delivered, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

10-minute Ramp and Uncertainty Reserve Down Requirement:

"10-minute Ramp and Uncertainty Reserve Down Requirement" shall mean the megawatts required to be maintained in the Reserve Zone, as 10-minute Ramp and Uncertainty Reserve Down. The 10-minute Ramp and Uncertainty Reserve Down Requirement is calculated in accordance with Operating Agreement, Schedule 1, section 1 and the PJM Manuals.

10-minute Ramp and Uncertainty Reserve Up:

"10-minute Ramp and Uncertainty Reserve Up" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 10 minutes and is provided by equipment that is electrically synchronized to the Transmission System and dispatchable by the Office of the Interconnection through economic dispatch.

10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price:

"10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price" shall mean the locational clearing price for 10-minute Ramp and Uncertainty Reserve Up at the location the 10-minute Ramp and Uncertainty Reserve Up is delivered, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

10-minute Ramp and Uncertainty Reserve Up Requirement:

"10-minute Ramp and Uncertainty Reserve Up Requirement" shall mean the megawatts required to be maintained in the Reserve Zone, as 10-minute Ramp and Uncertainty Reserve Up. The 10-

minute Ramp and Uncertainty Reserve Up Requirement is calculated in accordance with Operating Agreement, Schedule 1, section 1 and the PJM Manuals.

30-minute Ramp and Uncertainty Reserve:

"30-minute Ramp and Uncertainty Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes and is provided by equipment that is electrically synchronized to the Transmission System and dispatchable by the Office of the Interconnection through economic dispatch.

30-minute Ramp and Uncertainty Reserve Locational Clearing Price:

"30-minute Ramp and Uncertainty Reserve Locational Clearing Price" shall mean the locational clearing price for 30-minute Ramp and Uncertainty Reserve at the location the 30-minute Ramp and Uncertainty Reserve is delivered, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

30-minute Ramp and Uncertainty Reserve Requirement:

"30-minute Ramp and Uncertainty Reserve Requirement" shall mean the megawatts required to be maintained in the Reserve Zone, as 30-minute Ramp and Uncertainty Reserve. The 30-minute Ramp and Uncertainty Reserve Requirement is calculated in accordance with Operating Agreement, Schedule 1, section 1 and the PJM Manuals.

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of 30-minute Ramp and Uncertainty Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in the Reserve Zone, as 30-minute Reserve. The 30-minute Reserve Requirement is calculated in accordance with Operating Agreement, Schedule 1, section 1 and the PJM Manuals. The requirement can be satisfied by any combination of 30-minute Ramp and Uncertainty or Secondary Reserve resources.

60-minute Reserve:

"60-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 60 minutes of a request from the Office of the Interconnection dispatcher.

60-minute Reserve Market Clearing Price:

"60-minute Reserve Market Clearing Price" shall mean the market clearing marginal price for 60-minute Reserve, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

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, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

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.

Actual MWh

"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

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," as that term is used in this definition, 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 (10%) 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, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Agreement," "Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

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.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

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, section 7.4.

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, section 7.4.3.

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 18.17.4.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant 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), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant 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" shall refer 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 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.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

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.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e.,

the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Charge Mode.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource without a storage component, or that does not operate by charging its storage component from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

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.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Committed Offer:

The "Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

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.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A and the PJM Manuals.

Condense Energy Use:

"Condense Energy Use" shall mean the power (MW) used by a condensing resource while operating in condensing mode. The value must be less than or equal to the actual power consumed.

Condense Startup Cost:

"Condense Startup Cost" shall mean the applicable costs for a resource to transition from offline state to operate in condensing mode. Condense Startup Cost shall consist primarily of the unit's start heat input (adjusted by the performance factor) times the fuel cost associated with the transition from offline state to operate in condensing mode. It also may include operating costs, Maintenance Adders, emissions allowances/adders, and station service cost associated with the

transition from offline state to operate in condensing mode. Condense Startup Cost shall be capped at the applicable Start-Up Cost of the Cost-Based Offer.

Condense to Generate Cost:

"Condense to Generate Cost" shall mean the applicable costs for a resource to transition from operating in condensing mode to operating in generating mode. Condense to Generate Cost shall consist primarily of the unit's start heat input (adjusted by the performance factor) times the fuel cost associated with the transition from operating in condensing mode to operating in generating mode. It also may include operating costs, Maintenance Adders, emissions allowances/adders, and station service cost associated with the transition from operating in condensing mode to operating in generating mode. Condense to Generate Cost shall be capped at the applicable Start-Up Cost of the Cost-Based Offer.

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, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners 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. on file with the Commission, as amended from time to time.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

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, section 1.13.

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, section 1.13.

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 a Market Participant 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" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

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"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45) Schedule A. The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C, Attachment 3, section 2.

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, section 1.13.

Curtailment Service Provider:

"Curtailment 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, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant 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), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

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 Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-Ahead Scheduling Reserve:

"Day-Ahead Scheduling Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 60 minutes of a request from the Office of the Interconnection dispatcher and is comprised of 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve, Secondary Reserve, and 60-minute Reserve.

Day-Ahead Scheduling Reserve Requirement:

"Day-Ahead Scheduling Reserve Requirement" shall mean the megawatts required to be maintained in the Reserve Zone, as Day-Ahead Scheduling Reserve. The Day-Ahead Scheduling Reserve Requirement is calculated in accordance with Operating Agreement, Schedule 1, section 1 and the PJM Manuals. The requirement can be satisfied by any combination of 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve, Secondary Reserve, and 60-minute Reserve.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead State of Charge:

"Day-ahead State of Charge" shall mean the prospective State of Charge of an Energy Storage Resource Model Participant as offered into the Day-ahead Energy Market according to the procedures described in the PJM Manuals, measured in units of megawatt-hours. Day-ahead State of Charge for an interval represents the State of Charge at the beginning of that interval.

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, section 1.10.1B.

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, section 1.10.1B.

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 Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

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.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource in Discharge Mode.

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.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Synchronized Reserve;

10-minute Ramp and Uncertainty Reserve Up; 10-minute Ramp and Uncertainty Reserve Down; 30-minute Ramp and Uncertainty Reserve; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

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 have the same meaning provided in the Operating Agreement.

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, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Load Response Regulation Only Participant:

"Economic Load Response Regulation Only 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, section 1.5A, and is only eligible to participate in the PJM Regulation market.

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 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).

EFORd:

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

"Eligible Customer" shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

"Emergency Action" shall mean (1) any megawatt shortage of the Synchronized Reserve Requirement (as specified in the PJM Manuals) in the Reserve Zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses the Reserve Zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for the entire Reserve Zone.

Emergency Condition:

"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

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, section 8.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Make Whole

"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.

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 an operational limitation due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future 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 Operating Agreement, Schedule 2.

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

"Energy Transmission Injection Rights" shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

"Entity Providing Supply Services to Default Retail Service Provider" shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

"Environmental Laws" shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

"Environmentally-Limited Resource" shall mean a resource which 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 by a governmental authority to operating only during declared PJM capacity emergencies.

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.

Event of Default:

"Event of Default," as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

"Exercise of Buyer-Side Market Power" shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract

between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

"Export Credit Exposure" is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

"Export Nodal Reference Price" at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

"Export Transaction" shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

"Export Transaction Price Factor" for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

"Export Transaction Screening" shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny

or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

"Export Transactions Net Activity" shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

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.

Facilities Study:

"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer's New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

"FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 C.F.R. §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

"Financial Close" shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

"Financial Default" shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure

period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

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, section 5.2.2.

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, section 5.2.2(b).

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, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

"Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a

Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

"Foreign Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

"Forward Daily Natural Gas Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

"Forward Hourly Ancillary Services Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

"Forward Hourly LMPs" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

"FTR Credit Limit" shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

"FTR Credit Requirement" shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

"FTR Flow Undiversified" shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, "FTR Historical Value" shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

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

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, "FTR Monthly Credit Requirement Contribution" shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

"FTR Net Activity" shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR market.

FTR Portfolio Auction Value:

"FTR Portfolio Auction Value" shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:

"Full Notice to Proceed" shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

"Limited Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will

not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

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 Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

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.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

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.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, or 30-minute Ramp and Uncertainty Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

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, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor" means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

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 Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product 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 Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy market realized from a change in Real-time Energy Market megawatt output from a Day-ahead Energy Market megawatt assignment due to the net decrease in the total real-time reserve assignments across Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, and Secondary Reserve products from the total day-ahead reserve market megawatt assignment across those same reserve products as further described in the PJM Manuals.

Market Seller Offer Cap:

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

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 Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

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.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities; (ii) any physical facilities of the Transmission System that were in existence on or before March 20,

2003; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff; or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

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.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:

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

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

"Near-Term Transmission Service" shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. "Near-Term Transmission Service" includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

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.

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 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

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.

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direcct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

"New Entry Capacity Resource with State Subsidy" shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

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

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Curtailment Charge:

"Non-Curtailment Charge" shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

"Non-PAI Event" shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

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 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 Operating Agreement, Schedule 2.

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, or electric distribution companies to serve load.

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, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

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 or portions of a generation facility (including Behind The Meter Generation) that (i) are not Generation Capacity Resources, (ii) are not injecting into the grid for the portion of a generation facility that participates as a Demand Resource or as an Economic Load Response Participant unless permitted as an Economic Load Response Regulation Only Participant, (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.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-time Information System" or "OASIS" shall mean the electronic communication system and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS 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.

Open-Loop Hybrid Resource:

“Open-Loop Hybrid Resource” shall mean a Hybrid Resource with a storage component that operates by charging its storage component from the grid.

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.

Operating Reserve Demand Curve:

“Operating Reserve Demand Curve” shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

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 Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval 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 interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the interval 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 Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the interval 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 interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval 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 interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the interval 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 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, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

"PJM Region" shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

"PJMSettlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

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

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," or "PJM Open Access Transmission 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 Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

"Planning Period" shall have the meaning specified in 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 the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Delivery under 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 Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-appendix, section 8.

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.

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 PJMSettlement 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 – R - S

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 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 Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

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 Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

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.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

"Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/ MWh.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

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 is inclusive of Regulation-Down Service and Regulation-Up Service.

Regulation-Down Requirement:

"Regulation-Down Requirement" shall mean the required megawatts of performance-adjusted Regulation-Down Service capability to be maintained in a Regulation Zone. The Regulation-Down Requirement is defined as a set megawatt value by hour in accordance with the PJM Manuals, and can increase to account for additional operational uncertainty.

Regulation-Down Service

"Regulation-Down Service" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications and response capability to increase and decrease its output in the downward range from a set point or adjust load in response to a regulating-down control signal, in accordance with the specification in the PJM Manuals.

Regulation-Up Requirement:

"Regulation-Up Requirement" shall mean the required megawatts of performance-adjusted Regulation-Up Service capability to be maintained in a Regulation Zone. The Regulation-Up Requirement is defined as a set megawatt value by hour in accordance with the PJM Manuals, and can increase to account for additional operational uncertainty.

Regulation-Up Service

"Regulation-Up Service" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications and response capability to increase and decrease its output in the upward range from a set point or adjust load in response to a regulating-up control signal, in accordance with the specification 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.

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 or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM 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.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that 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 constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

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, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), 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 Tariff, Attachment K-Appendix, section 7.4.2; 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.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Seasonal Facility Rating:

"Seasonal Facility Rating" shall mean a Transmission Facility Rating that:

(a) Applies to a specified season, where seasons are defined by the Office of the Interconnection to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies.

(c) Is evaluated annually, if not more frequently, for each season in the future for which Transmission Service can be requested

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes, from the request of the Office of the Interconnection, and is provided by equipment that is not electrically synchronized to the Transmission System or that is synchronized to the Transmission System but not eligible to provide 30-minute Ramp and Uncertainty Reserve.

Secondary Reserve Locational Clearing Price:

"Secondary Reserve Locational Clearing Price" shall mean the locational clearing price for Secondary Reserve at the location the Secondary Reserve is delivered, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors,

electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates**.**

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual

Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

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, section 1.5A.02, 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, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

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

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

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, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in the storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

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 in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

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.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant 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 Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in the Reserve Zone, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Locational Clearing Price:

"Synchronized Reserve Locational Clearing Price" shall mean the locational clearing price for Synchronized Reserve at the location the Synchronized Reserve is delivered, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in the Reserve 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. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

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, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the

Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

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, section 5.2.3, 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, section 7.4.3.

Third Incremental Auction:

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

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, section 5.1.

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 Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Facility Rating:

"Transmission Facility Rating" shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment. Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

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 Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

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 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, section 5.

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 Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

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.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

Updated VRR Curve Decrement:

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

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, section 1.10.1A.

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, section 1.5A.6.

Variable Resource Requirement Curve:

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:
"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

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

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that the estimated operating reserve capacity is less than the forecasted Synchronized Reserve Requirement and a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Synchronized, and (iv) Operating Reserve - Supplemental. Subject to the provisions of Tariff, Schedules 1 through 6, the Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Provider shall administer the purchases by Transmission Customers of these Ancillary Services. PJMSettlement shall be the Counterparty to the Ancillary Services provided to the Transmission Customer; provided, however, that PJMSettlement shall not be the contracting party to bilateral transactions between market participants or with respect to a self-schedule or self-supply relating to Ancillary Services. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Tariff, Schedule 3, Tariff, Schedule 4, and Tariff, Schedule 5) from a third party or by self-supply when technically feasible. The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Service provided by the Transmission Provider in conjunction with its

provision of transmission services as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system.

3.5 Operating Reserve

Rules regarding Operating Reserve markets may be found in Tariff, Attachment K-Appendix and parallel provisions in Operating Agreement, Schedule 1.

3.6

[reserved]

SCHEDULE 5
Operating Reserve

Rules regarding Operating Reserve markets may be found in Operating Agreement, Schedule 1 and parallel provisions in Tariff, Attachment K-Appendix.

SCHEDULE 6

[reserved]

Revisions for Both

PJM Open Access Transmission,

Attachment K-Appendix

and

Operating Agreement,

Schedule 1

(Clean Format)

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 below. 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 below.

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 PJMSettlement 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 Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 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. The Curtailment Service Provide shall not include Critical Natural Gas Infrastructure end-use customers in the registration. 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 and is not an Economic Load Response

Regulation Only registration that will inject power onto the distribution system and in accordance with the Manuals.

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 this section 1.5A, including this subsection 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 PJMSettlement 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 this section 1.5A, including this subsection 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.

An Economic Load Response Regulation Only registration may also participate in the Regulation market when the end-use customer is injecting power onto the distribution grid if it meets the following additional requirements to participate when injecting:

- The end-use customer(s) must be on an associated electric distribution company's net energy metering tariff; and

- The registration must use sub-metered data for measurement and verification in accordance with Tariff, Attachment K-Appendix, section 1.5A.4.

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 below, 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 Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, 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 Market Monitoring Unit 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 Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-

Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 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 above, 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 Economic Load Response Participant Resource Provision of Synchronized Reserve or Secondary Reserve.

(a) A Batch Load Economic Load Response Participant resource may provide Synchronized Reserve or Secondary Reserve 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 Economic Load Response Participant 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 Economic Load Response Participant resource" pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant resource.

(b) A Batch Load Economic Load Response Participant resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Secondary Reserve, 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 Secondary Reserve, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant 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 Secondary Reserve, 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 Secondary Reserve, 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 Secondary Reserve to reduce load.

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

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 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 Secondary 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 above 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;

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 Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 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 an Economic Load Response Participant 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 above 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 an Economic Load Response Participant 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 above, 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.

1.7 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, Energy Storage Resources, and Market Participants purchasing Direct Charging Energy to charge Open-Loop Hybrid Resources 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.

1.7.2B Energy Storage Resources and Open-Loop Hybrid Resources.

Energy purchased from the PJM Interchange Energy Market by a Market Participant of an Open-Loop Hybrid Resource for charging such resource, or that an Energy Storage Resource purchases from the PJM Interchange Energy Market, must be Direct Charging Energy. Energy Storage Resources and Open-Loop Hybrid Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

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, Economic Load Response Participant 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 Operating Agreement, section 14, 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 Tariff, section 36.1.1, 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, Generation Interconnection Agreement under Part IX of the PJM Tariff, or Wholesale Market Participation Agreement under Part IX of the PJM Tariff, or functionally equivalent 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 Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant 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.

(d) The Office of the Interconnection shall ensure that day-ahead schedules for Energy Storage Resource Model Participants take into account the Day-ahead State of Charge, the Minimum State of Charge, and the Maximum State of Charge parameters of Energy Storage Resource Model Participants. When dispatching Energy Storage Resource Model Participants in real-time, the Office of the Interconnection shall take into account the Real-time State of Charge, the Minimum State of Charge, and the Maximum State of Charge parameters of Energy Storage Resource Model Participants.

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 applicable interval 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 the applicable interval, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there 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 Operating Agreement, Schedule 1, section 3. 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 Operating Agreement, Schedule 1, 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 Real-time Settlement Interval during the month. For each Real-time Settlement Interval 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 Real-time Settlement Interval for all of the energy delivered. Conversely, for each Real-time Settlement Interval 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 Real-time Settlement Interval 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 Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 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 Tariff, Schedule 1; Tariff, Schedule 1A;Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 9; and Tariff, Schedule 10 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.

(iv) The Office of the Interconnection is not responsible for determining Relevant Electric Retail Regulatory Authority-jurisdictional retail rates, and the monthly netting provision in section 1.7.10(d)(i) above does not determine whether a retail sale of station power has occurred in a month. Furthermore, notwithstanding any provision of subsection (d)(i) or (d)(ii) to the contrary, any net output determined for a Market Seller for Station Power purposes shall, as more fully set forth in the PJM manuals, take account of MWh values submitted to the Office of the Interconnection via its metering reporting systems by the Market Seller or the applicable Electric Distribution Company designated to make such submission, that reflect the Market Seller's purchase of energy at retail to meet its Station Power needs.

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 [Reserved.]

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant 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 Economic Load Response Participant 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. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if (i) its entire output has been designated as emergency energy, or (ii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Synchronized Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. 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 the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain through the Day-Ahead Market and the Real-Time Market for the Reserve Zone an amount of Synchronized Reserve based on the applicable Operating Reserve Demand Curve and the Synchronized Reserve Requirement for the Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 10-minute period, provided that response can be sustained for at least 30 minutes as specified in the PJM Manuals.

1.7.19A.01 10-minute Ramp and Uncertainty Reserve Up.

(a) 10-minute Ramp and Uncertainty Reserve Up shall be supplied from synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region that are dispatchable by the Office of the Interconnection through economic dispatch, as specified in the PJM Manuals. A resource is not eligible to provide 10-minute Ramp and Uncertainty Reserve Reserve Up if (i) its entire output has been designated as emergency energy, or (ii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide 10-minute Ramp and Uncertainty Reserves Up. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide 10-minute Ramp and Uncertainty Reserve Up, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering 10-minute Ramp and Uncertainty Reserve Up shall comply with applicable standards and requirements for 10-minute Ramp and Uncertainty Reserve Up capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain through the Day-Ahead Market and the Real-Time Market for the Reserve Zone an amount of 10-minute Ramp and Uncertainty Reserve Up based on the applicable Operating Reserve Demand Curve and the 10-minute Ramp and Uncertainty Reserve Up Requirement for the Reserve Zone. As further discussed in the PJM Manuals, the 10-minute Ramp and Uncertainty Reserve Up Requirement shall be the sum of:

(1) the adjusted forecast net-load ramp, defined as the difference in the adjusted forecast net-load 10 minutes beyond the current energy dispatch interval minus the adjusted forecast net-load for the current energy dispatch interval, and

(2) the net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts, over the same forward period.

Where the adjusted forecast net load shall be calculated as follows:

adjusted forecast net-load = load forecast - wind forecast - solar forecast - expected energy from resources starting-up.

The 10-minute Ramp and Uncertainty Reserve Up Requirement is floored at 0 MW.

(c) The 10-minute Ramp and Uncertainty Reserve Up capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 10-minute period provided that response can be sustained for at least 60 minutes as specified in the PJM Manuals.

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve shall be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region that are not eligible to provide 30-minute Ramp and Uncertainty Reserve, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide Secondary Reserves. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain through the Day-Ahead Market and the Real-Time Market for the Reserve Zone an amount of Secondary Reserve such

that the sum of the 30-minute Ramp and Uncertainty Reserve and Secondary Reserve meets the 30-minute Reserve Requirement for the Reserve Zone based on the applicable Operating Reserve Demand Curve. The 30-minute Reserve Requirement shall be the sum of the 30-minute Ramp and Uncertainty Reserve Requirement and the largest contingency as further discussed in the PJM Manuals.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, provided that response can be sustained for at least four hours as specified in the PJM Manuals.

1.7.19A.03 30-minute Ramp and Uncertainty Reserve.

(a) 30-minute Ramp and Uncertainty Reserve shall be supplied from synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region that are dispatchable by the Office of the Interconnection through economic dispatch, as specified in the PJM Manuals. A resource is not eligible to provide 30-minute Ramp and Uncertainty Reserve if (i) its entire output has been designated as emergency energy, or (ii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide 30-minute Ramp and Uncertainty Reserve. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide 30-minute Ramp and Uncertainty Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering 30-minute Ramp and Uncertainty Reserve shall comply with applicable standards and requirements for 30-minute Ramp and Uncertainty Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain through the Day-Ahead Market and the Real-Time Market for the Reserve Zone an amount of 30-minute Ramp and Uncertainty Reserve based on the applicable Operating Reserve Demand Curve and the 30-minute Ramp and Uncertainty Reserve Requirement for the Reserve Zone. As further discussed

in the PJM Manuals, the 30-minute Ramp and Uncertainty Reserve Requirement shall be the sum of:

(1) the adjusted forecast net-load ramp, defined as the difference in the adjusted forecast net-load 30 minutes beyond the current energy dispatch interval minus the adjusted forecast net-load 10 minutes beyond the current energy dispatch interval, and

(2) the net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts, over the same forward period.

Where the adjusted forecast net load would be calculated as follows:

adjusted forecast net-load = load forecast - wind forecast - solar forecast - expected energy from resources starting-up.

The 30-minute Ramp and Uncertainty Reserve Requirement is floored at 0 MW.

(c) The 30-minute Ramp and Uncertainty Reserve capability of a generation resource shall be the increase in energy output or load reduction achievable by the generation resource and the Economic Load Response Participant resource within a continuous 30-minute period, provided that response can be sustained for at least four hours as specified in the PJM Manuals.

1.7.19A.04 60-minute Reserve.

(a) 60-minute Reserve can be supplied from synchronized generation resources and non-synchronized generation resources that can start and reach Economic Minimum within 30 minutes and/or Economic Load Response Participant resources. Resources supplying 60-minute Reserve must be located within the metered boundaries of the PJM Region. A resource is not eligible to provide 60-minute Reserve if (i) its entire output has been designated as emergency energy, (ii) it is not available to provide energy, or (iii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide 60-minute Reserve. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

All other non-emergency generation capacity resources available to provide energy shall also be available to provide 60-minute Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering 60-minute Reserve shall comply with applicable standards and requirements for 60-minute Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall procure through the Day-ahead Energy Market for the Reserve Zone an amount of 60-minute Reserve such that the sum of the 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve, Secondary Reserve, and 60-minute Reserve meets the Day-Ahead Scheduling Reserve Requirement for the Reserve Zone based on the applicable Operating Reserve Demand Curve. As further described in the PJM Manuals, the Day-Ahead Scheduling Reserve Requirement may vary hourly and shall consider historical load, solar, and wind forecast error as well as historical forced outage rates and be adjusted based on an assessment conducted by the Office of Interconnection to evaluate risk for the Operating Day.

(c) The 60-minute Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 60-minute period, minus the increase in energy output or load reduction achievable within a continuous 30-minute period, provided that response can be sustained for at least four hours as specified in the PJM Manuals.

1.7.19A.05 10-minute Ramp and Uncertainty Reserve Down.

(a) 10-minute Ramp and Uncertainty Reserve Down shall be supplied from synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region that are dispatchable by the Office of the Interconnection through economic dispatch, as specified in the PJM Manuals. A resource is not eligible to provide 10-minute Ramp and Uncertainty Reserve Down if (i) its entire output has been designated as emergency energy, or (ii) it is a nuclear, wind, or solar unit, or a Hybrid Resource comprised exclusively of wind and solar components, unless the Market Seller of such a resource has obtained written approval from the Office of the Interconnection to provide 10-minute Ramp and Uncertainty Reserve Down. To obtain such approval, the Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written request for exemption and provide documentation to support the resource's ability to follow dispatch at the direction of the Office of the Interconnection, such as historical operating data showing voluntary response to reserve events and/or technical information about the physical operation of the resource. The Office of the Interconnection and the Market Monitoring Unit shall review, in an open and transparent manner as between the Market Seller, the Market Monitoring Unit, and the Office of the Interconnection, the information and documentation in support of the request for approval to provide reserves. No later than 30 Business Days from the date of data submittal supporting the request, the Office of the Interconnection shall determine, with the advice and input of the Marketing Monitoring Unit, whether the resource will be permitted to provide reserves and provide written notification to the Market Seller of such determination. If the request is denied,

the Office of the Interconnection shall include in the notice a written explanation for the denial. All other non-emergency generation capacity resources available to provide energy shall also be available to provide 10-minute Ramp and Uncertainty Reserve Down, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering 10-minute Ramp and Uncertainty Reserve Down shall comply with applicable standards and requirements for 10-minute Ramp and Uncertainty Reserve Down capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain through the Day-Ahead Market and the Real-Time Market for the Reserve Zone an amount of 10-minute Ramp and Uncertainty Reserve Down based on the applicable Operating Reserve Demand Curve and the 10-minute Ramp and Uncertainty Reserve Down Requirement for the Reserve Zone. As further discussed in the PJM Manuals, the 10-minute Ramp and Uncertainty Reserve Down Requirement shall be the difference between:

(1) the net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts, over the same forward period as described in (2), and

(2) the forecast net-load ramp, defined as the difference in the forecast net-load 10 minutes beyond the current energy dispatch interval minus the forecast net-load for the current energy dispatch interval.

Where the forecast net load would be calculated as follows:

forecast net-load = load forecast - wind forecast - solar forecast.

The 10-minute Ramp and Uncertainty Reserve Down Requirement is floored at 0 MW.

(c) The 10-minute Ramp and Uncertainty Reserve Down capability of a generation resource shall be the decrease in energy output or load increase achievable by the generation resource and the Economic Load Response Participant resource within a continuous 10-minute period, provided that response can be sustained for at least 60 minutes.

1.7.19B Bilateral Transactions Regarding Regulation.

(a) In addition to transactions in the Regulation market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, 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 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 in the

markets for Regulation respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, 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 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 of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation 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 used to meet the bilateral contract seller's obligation to deliver Regulation 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, 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 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 Economic Load Response Participant resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Economic Load Response Participant 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 Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

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) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to 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.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, 30-minute Ramp and Uncertainty Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, 30-minute Ramp and Uncertainty Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, or Synchronized Reserve 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 Operating Agreement, Schedule 1, section 1.13. 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 energy uplift 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 Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 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 $2,000/MWh), 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. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. 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 Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, 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.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(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), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage 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 must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead 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 are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 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 Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

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) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; and (14) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down

time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

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 sections 1.10.9A or 1.10.9B below;

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 a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

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 Tariff, Attachment DD-1,

section A.2 and the parallel provision of RAA, Schedule 6, $2,000/megawatt-hour;

b) an approved 60-minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,550/megawatt-hour; and

c) an approved 120-minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, $1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation-Up Service and/or Regulation-Down Service shall submit offer(s) for the applicable Regulation service(s) for each 30 minute Regulation clearing interval 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-Up and/or Regulation-Down being offered, which must equal or exceed 0.1 megawatts, in the Regulation Zone for which such Regulation-Up and/or Regulation-Down Service is offered, the price of the capability offer in dollars per MW, the price of the mileage 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 for Regulation-Up and/or Regulation-Down Service(s). Such offers may vary for each 30 minute Regulation clearing interval, and may be updated each 30 minute Regulation clearing interval, up to 35 minutes before the applicable 30 minute Regulation clearing interval during the Operating Day. The total of the applicable Regulation service mileage offer multiplied by the applicable historical average mileage used in the market clearing plus the applicable Regulation service capability offer shall not exceed $50/megawatt-hour, for the Regulation-Down Service and Regulation-Up Service, independently. In addition to any market-based offer for Regulation-Up and/or Regulation-Down Service, 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 for Regulation-Down Service;

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 mileage offer for Regulation-Down Service and Regulation-Up Service; and

a. Only Regulation-only resources may include all variable operation and maintenance expenses in the mileage offer, as defined in the PJM Manuals.

iii. An adder of up to $6.00 per megawatt of Regulation provided applied to the capability offer for Regulation-Down Service and an adder of up to $6.00 per megawatt of Regulation provided applied to the capability offer Regulation-Up Service.

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 Costs and No-load Costs, 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 energy uplift 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 Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(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) (i) Offers to Supply Synchronized Reserve By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) 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 Tariff, Attachment DD, is capable of providing Synchronized Reserve as specified in section 1.7.19A(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (i) are capable of providing Synchronized Reserve, as specified in section 1.7.19A(a) and in the PJM Manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve, as applicable.

(3) Consistent with the resource's offer to supply energy, such offers for the supply of Synchronized Reserve may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. 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, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not be below $0/MWh and shall not exceed a reserve soft offer cap of $10.00/MWh plus the expected value of the penalty for failing to provide Synchronized Reserve unless

the Market Participant submits documentation to the office of the Interconnection and the Market Monitoring Unit that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide Synchronized Reserve in the Day-ahead Energy Market and expected loss of revenue due to Synchronized Reserve deployment in either the Day-ahead or Real-time Energy Markets that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. The expected value of the penalty shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website and shall be calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating

configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, 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 request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve shall submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not be below $0/MWh and shall not exceed $10.00/MWh plus the expected value of the penalty for failing to provide Synchronized Reserve, unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide Synchronized Reserve in the Day-ahead Energy Market and expected loss of revenue due to Synchronized Reserve deployment in either the Day-ahead or Real-time Energy Markets that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. The expected value of the penalty is determined in accordance with section 1.10.1A(j)(i)(3) above. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

(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, shutdown 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 65 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 an Economic Load Response Participant 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 Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant 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. An Economic Load Response Participant 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 Economic Load Response Participant 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) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) 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 Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (i) are capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall not be below $0/MWh and shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide Secondary Reserve in the Day-ahead Energy Market and expected penalties that exceed $10/MWh in both the Day-ahead Energy Market and Real-Time Energy Market, as determined in accordance with the PJM Manuals. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. 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 subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2)

(A) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) Economic Maximum MW.

(B) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) Economic Maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, 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 request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserve by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall not be below $0/MWh and shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be

associated with maintaining availability to provide Secondary Reserve in the Day-ahead Energy Market and expected penalties that exceed $10.00/MWh in the Day-ahead or Real-time Energy Markets, as determined in accordance with the PJM Manuals. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine 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.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie 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.

(o) (i) Offers to Supply 10-minute Ramp and Uncertainty Reserve Up by Generation Resources

(1) 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 Tariff, Attachment DD, that is available for energy, is capable of providing 10-minute Ramp and Uncertainty Reserve Up, as specified in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply 10-minute Ramp and Uncertainty Reserve Up, or otherwise make their 10-minute Ramp and Uncertainty Reserve Up capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within ten minutes from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision. Notwithstanding the foregoing, a resource owner/operator that purchased gas in advance of a Day-ahead Energy Market

commitment during a Cold Weather Alert would meet the reserve must offer requirement so long as such resource is self-scheduled and produces energy at or above the installed capacity equivalent of the resource's committed Accredited UCAP capacity minus any MW quantity that is offered to provide reserves.

(2) Market Sellers of all other generation resources that (i) are capable of providing 10-minute Ramp and Uncertainty Reserve Up, as specified in section 1.7.19A.01 and in the PJM Manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide 10-minute Ramp and Uncertainty Reserve Up in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources, Hybrid Resources, and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply 10-minute Ramp and Uncertainty Reserve Up, as applicable.

(3) Offers for the supply of 10-minute Ramp and Uncertainty Reserve Up shall not have an offer price below $0/MWh. In the Day-ahead Energy Market, the offer price shall not exceed $10.00/MWh unless the Market Participant provides documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 10-minute Ramp and Uncertainty Reserve Up that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. Offers for the supply of 10-minute Ramp and Uncertainty Reserve Up in the Real-time Energy Market shall not exceed $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. 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 subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available 10-minute Ramp and Uncertainty Reserve Up Capability of Generation Resources

(1) For each offer to supply 10-minute Ramp and Uncertainty Reserve Up by a generation resource, the Office of the Interconnection shall determine the MW of available 10-minute Ramp and Uncertainty Reserve Up capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources. Hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources may submit their available 10-

minute Ramp and Uncertainty Reserve Up capability as part of their offer into the 10-minute Ramp and Uncertainty Reserve Up market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(o)(i) above must submit a 10-minute Ramp and Uncertainty Reserve Up offer which specifies the MW of 10-minute Ramp and Uncertainty Reserve Up capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available 10-minute Ramp and Uncertainty Reserve Up capability shall be based on the resource's available 10-minute Ramp and Uncertainty Reserve Up capability and the following offer parameters submitted as part of the resource's energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) Economic Maximum MW.

(iii) Offers to Supply 10-minute Ramp and Uncertainty Reserve Up by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market, is capable of providing 10-minute Ramp and Uncertainty Reserve Up, as specified in section 1.7.19A.01(a) and in the PJM Manuals, and wishes to make their resources available to supply 10-minute Ramp and Uncertainty Reserve Up shall submit offers to supply 10-minute Ramp and Uncertainty Reserve Up from such resources, where such offers shall specify the megawatts of 10-minute Ramp and Uncertainty Reserve Up being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) Offers for the supply of 10-minute Ramp and Uncertainty Reserve Up by Economic Load Response Participant resources shall not be below $0/MWh. In the Day-ahead Energy Market, the offer price shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 10-minute Ramp and Uncertainty Reserve Up that exceed $10/MWh, as determined in accordance with the PJM Manuals. Offers for the supply of 10-minute Ramp and Uncertainty Reserve Up in the Real-time Energy Market shall not exceed $0.00/MWh. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

(p) (i) Offers to Supply 30-minute Ramp and Uncertainty Reserve By Generation Resources

(1) 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 Tariff, Attachment DD, that is available for energy, is capable of providing 30-minute Ramp and Uncertainty Reserve, as specified in section 1.7.19A.03(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply 30-minute Ramp and Uncertainty Reserve, or otherwise make their 30-minute Ramp and Uncertainty Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision. Notwithstanding the foregoing, a resource owner/operator that purchased gas in advance of a Day-ahead Energy Market commitment during a Cold Weather Alert would meet the reserve must offer requirement so long as such resource is self-scheduled and produces energy at or above the installed capacity equivalent of the resource's committed Accredited UCAP capacity minus any MW quantity that is offered to provide reserves.

(2) Market Sellers of all other generation resources that (i) are capable of providing 30-minute Ramp and Uncertainty Reserve, as specified in section 1.7.19A.03(a) and in the PJM Manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide 30-minute Ramp and Uncertainty Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources, Hybrid Resources, and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply 30-minute Ramp and Uncertainty Reserve, as applicable.

(3) Offers for the supply of 30-minute Ramp and Uncertainty Reserve shall not be below $0/MWh. In the Day-Ahead Energy Market, the offer price shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 30-minute Ramp and Uncertainty Reserve that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. Offers for the supply of 30-minute Ramp

and Uncertainty Reserve in the Real-Time Energy Market shall not exceed $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. 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 subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available 30-minute Ramp and Uncertainty Reserve Capability of Generation Resources

(1) For each offer to supply 30-minute Ramp and Uncertainty Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available 30-minute Ramp and Uncertainty Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources. Hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources may submit their available 30-minute Ramp and Uncertainty Reserve capability as part of their offer into the 30-minute Ramp and Uncertainty Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(p)(i) above must submit a 30-minute Ramp and Uncertainty Reserve offer which specifies the MW of 30-minute Ramp and Uncertainty Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available 30-minute Ramp and Uncertainty Reserve capability shall be based on the resource's available 30-minute Ramp and Uncertainty Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) Economic Maximum MW.

(iii) Offers to Supply 30-minute Ramp and Uncertainty Reserve by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market, is capable of providing 30-minute Ramp and Uncertainty Reserve as specified in section 1.7.19A.03(a) and in the PJM Manuals, and wishes to make their resources available to supply 30-minute Ramp and Uncertainty Reserve shall submit offers to supply 30-minute Ramp and Uncertainty Reserve from such resources, where such offers shall specify the megawatts of 30-minute Ramp and Uncertainty Reserve being offered, which must equal or exceed 0.1 megawatts

and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) Offers for the supply of 30-minute Ramp and Uncertainty Reserve by Economic Load Response Participant resources shall not be below $0/MWh. In the Day-ahead Energy Market, the offer price shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 30-minute Ramp and Uncertainty Reserve that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. Offers for the supply of 30-minute Ramp and Uncertainty Reserve in the Real-time Energy Market shall not exceed $0.00/MWh. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

(q) (i) Offers to Supply 60-minute Reserve By Generation Resources

(1) 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 Tariff, Attachment DD, that is available for energy, is capable of providing 60-minute Reserve, as specified in section 1.7.19A.04(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply 60-minute Reserve, or otherwise make their 60-minute Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within sixty minutes from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision. Notwithstanding the foregoing, a resource owner/operator that purchased gas in advance of a Day-ahead Energy Market commitment during a Cold Weather Alert would meet the reserve must offer requirement so long as such resource is self-scheduled and produces energy at or above the installed capacity equivalent of the resource's committed Accredited UCAP capacity minus any MW quantity that is offered to provide reserves.

(2) Market Sellers of all other generation resources that (i) are capable of providing 60-minute Reserve, as specified in section 1.7.19A.04(a) and in the PJM Manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy

Market shall be deemed to have made their reserve capability available to provide 60-minute Reserve in the Day-ahead Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources, Hybrid Resources, and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply 60-minute Reserve, as applicable.

(3) Offers for the supply of 60-minute Reserve shall not be below $0/MWh and shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 60-minute Reserve that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. Consistent with the resource's offer to supply energy, such offers 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 subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available 60-minute Reserve Capability of Generation Resources

(1) For each offer to supply 60-minute Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available 60-minute Reserve capability offered in the Day-ahead Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources. Hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources may submit their available 60-minute Reserve capability as part of their offer into the 60-minute Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(q)(i) above must submit a 60-minute Reserve offer which specifies the MW of available 60-minute Reserve capability in order to remain compliant with such requirements.

(2)

(A) An on-line generation resource's available 60-minute Reserve capability, shall be based on the resource's available 60-minute Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) Economic Maximum MW.

(B) An off-line generation resource's available 60-minute Reserve capability, shall be based on the resource's available 60-minute Reserve

capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) Economic Maximum MW.

(C) For generation resources capable of synchronous condensing, the resource's available 60-minute Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) Economic Maximum MW.

(iii) Offers to Supply 60-minute Reserve by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market, is capable of providing 60-minute Reserve, as specified in section 1.7.19A.04(a) and in the PJM Manuals, and wishes to make their resources available to supply 60-minute Reserve shall submit offers to supply 60-minute Reserve from such resources, where such offers shall specify the megawatts of 60-minute Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer.

(2) All 60-minute Reserve offers by Economic Load Response Participant resources shall not be below $0/MWh and shall not exceed $10.00/MWh unless the Market Participant submits documentation that demonstrates costs above this level in the form specified in the PJM Manuals. Such costs may only be associated with maintaining availability to provide 60-minute Reserve that exceed $10.00/MWh, as determined in accordance with the PJM Manuals. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

(r) (i) Offers to Supply 10-minute Ramp and Uncertainty Reserve Down By Generation Resources

(1) 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 Tariff, Attachment DD, that is available for energy, is capable of providing 10-minute Ramp and Uncertainty Reserve Down, as specified in section 1.7.19A.05(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply 10-minute

Ramp and Uncertainty Reserve Down, or otherwise make their 10-minute Ramp and Uncertainty Reserve Down capability available. Such offers shall be for an amount equal to the resource's available energy reduction achievable within ten minutes from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision. Notwithstanding the foregoing, a resource owner/operator that purchased gas in advance of a Day-ahead Energy Market commitment during a Cold Weather Alert would meet the reserve must offer requirement so long as such resource is self-scheduled and produces energy at or above the installed capacity equivalent of the resource's committed Accredited UCAP capacity accounting for any MW quantity that is offered to provide reserves.

(2) Market Sellers of all other generation resources that (i) are capable of providing 10-minute Ramp and Uncertainty Reserve Down, as specified in section 1.7.19A.05(a) and in the PJM Manuals, (ii) are located within the metered boundaries of the PJM Region, and (iii) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide 10-minute Ramp and Uncertainty Reserve Down in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources, Hybrid Resources, and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply 10-minute Ramp and Uncertainty Reserve Down, as applicable.

(3) Offers for the supply of 10-minute Ramp and Uncertainty Reserve Down shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. 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 subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available 10-minute Ramp and Uncertainty Reserve Down Capability of Generation Resources

(1) For each offer to supply 10-minute Ramp and Uncertainty Reserve Down by a generation resource, the Office of the Interconnection shall determine the MW of available 10-minute Ramp and Uncertainty Reserve Down capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the

Interconnection will not make such determination for hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources. Hydroelectric generation resources, Hybrid Resources, or Energy Storage Resources may submit their available 10-minute Ramp and Uncertainty Reserve Down capability as part of their offer into the 10-minute Ramp and Uncertainty Reserve Down market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(r)(i) above must submit a 10-minute Ramp and Uncertainty Reserve Down offer which specifies the MW of 10-minute Ramp and Uncertainty Reserve Down capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available 10-minute Ramp and Uncertainty Reserve Down capability shall be based on the resource's available 10-minute Ramp and Uncertainty Reserve Down capability and the following offer parameters submitted as part of the resource's energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) Economic Maximum MW.

(iii) Offers to Supply 10-minute Ramp and Uncertainty Reserve Down by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to increase demand into the Day-ahead Energy Market and Real-time Energy Market, is capable of providing 10-minute Ramp and Uncertainty Reserve Down, as specified in section 1.7.19A.05(a) and in the PJM Manuals, and wishes to make their resources available to supply 10-minute Ramp and Uncertainty Reserve Down shall submit offers to supply 10-minute Ramp and Uncertainty Reserve Down from such resources, where such offers shall specify the megawatts of 10-minute Ramp and Uncertainty Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All 10-minute Ramp and Uncertainty Reserve Down offers by Economic Load Response Participant resources shall be for $0.00/MWh. 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), section 1.10.9B below, and the PJM Manuals, as applicable.

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 section 1.10.9 below or Operating Agreement, Schedule 1, section 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 Costs, No-load Costs, 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 above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(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 Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, 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 must equal or exceed 0.1 megawatts, in minimum increments of 0.1 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 Day-ahead Energy Market and/or 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 and not dispatchable by 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.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve, 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve, 60-minute Reserve, or 10-minute Ramp and Uncertainty Reserve Down.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

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.

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 Transfer 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 Transfer 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.

1.10.7 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 above 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 PRD Providers; (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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, section 3.3A. 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, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants 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 Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. 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, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* 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 Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. 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 Operating Agreement, section 18.17.1, 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 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

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 Costs.

(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 65 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.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 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:

(i) 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 may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) 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, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 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.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 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, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; and (7) Synchronized Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, 10-minute Ramp and Uncertainty Up, 30-minute Ramp and Uncertainty, 10-minute Ramp and Uncertainty Down, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or

(2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d). Additionally, Market Sellers may not update their offers for 60-minute Reserve after the close of the Day-ahead Energy Market.

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; and (8) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Operating Agreement, Schedule 1, section 1.10 and Operating Agreement, Schedule 1, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), 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 as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch 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. In addition, the Office of the Interconnection shall utilize Ambient-Adjusted Ratings for Transmission Facilities as an input into the real-time security constrained economic dispatch.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A 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 performing the security constrained economic dispatch of the system, 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. The 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 buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on transmission facilities as defined in the PJM Manuals.

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 or self-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 or self-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.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time security constrained economic dispatch program or other operational reasons, the most recent State

Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(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 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 upon receipt.

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 Economic Load Response Participant 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 Operating Agreement, Schedule 1, 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 Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant 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 energy 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 shall satisfy its Synchronized Reserve Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from available pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the Synchronized Reserve Requirement of the Reserve Zone. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirement, 10-minute Ramp and Uncertainty Reserve Up Requirement; 10-minute Ramp and Uncertainty Reserve Down Requirement; 30-minute Ramp and Uncertainty Reserve Requirement, 30-minute Reserve Requirement; in the day-ahead energy and reserve markets, the Day-Ahead Scheduling Reserve Requirement; and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant 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 energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B 10-minute Ramp and Uncertainty Reserve Up.

(a) A Market Buyer shall satisfy its 10-minute Ramp and Uncertainty Reserve Up Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.001. PJMSettlement shall be the Counterparty to the purchases and sales of 10-minute Ramp and Uncertainty Reserve Up in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain 10-minute Ramp and Uncertainty Reserve Up from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 10-minute Ramp and Uncertainty Reserve Up Requirement of the Reserve Zone. The Office of the Interconnection shall clear both the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Market and the Real-time 10-minute Ramp and Uncertainty Reserve Up Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the 10-minute Ramp and Uncertainty Reserve Up Market. Resources eligible to sell 10-minute Ramp and Uncertainty Reserve Up shall be cleared to provide 10-minute Ramp and Uncertainty Reserve Up on the basis of each generation resource's and/or Economic Load Response Participant resource's 10-minute Ramp and Uncertainty Reserve Up offer and the product substitution cost of providing 10-minute Ramp and Uncertainty Reserve Up, energy and any other product the resource is capable of providing; and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirement, 10-minute Ramp and Uncertainty Reserve Up Requirement; 10-minute Ramp and Uncertainty Reserve Down Requirement; 30-minute Ramp and Uncertainty Reserve Requirement; 30-minute Reserve Requirement; in the day-ahead energy and reserve markets, the Day-Ahead Scheduling Reserve Requirement; and, in the real-time energy and reserve markets, Regulation Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for 10-minute Ramp and Uncertainty Reserve Reserve Up through economic dispatch, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good

Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer shall satisfy its Secondary Reserve Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of the Reserve Zone not otherwise satisfied by resources providing 30-minute Ramp and Uncertainty Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement; 10-minute Ramp and Uncertainty Reserve Up Requirement; 10-minute Ramp and Uncertainty Reserve Down Requirement; 30-minute Ramp and Uncertainty Reserve Requirement; 30-minute Reserve Requirement; in the day-ahead energy and reserve markets, the Day-Ahead Scheduling Reserve Requirement; and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4D 10-minute Ramp and Uncertainty Reserve Down.

(a) A Market Buyer shall satisfy its 10-minute Ramp and Uncertainty Reserve Down Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.002. PJMSettlement shall be the Counterparty to the purchases and sales of 10-minute Ramp and Uncertainty Reserve Down in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain 10-minute Ramp and Uncertainty Reserve Down from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 10-minute Ramp and Uncertainty Reserve Down Requirement of the Reserve Zone. The Office of the Interconnection shall clear both the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Market and the Real-time 10-minute Ramp and Uncertainty Reserve Down Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the 10-minute Ramp and Uncertainty Reserve Down Market. Resources eligible to sell 10-minute Ramp and Uncertainty Reserve Down shall be cleared to provide 10-minute Ramp and Uncertainty Reserve Down on the basis of each generation resource's and/or Economic Load Response Participant resource's cost associated with the energy dispatch to provide 10-minute Ramp and Uncertainty Reserve Down and any opportunity cost between providing 10-minute Ramp and Uncertainty Reserve Down and any other product the resource is capable of providing; and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement; 10-minute Ramp and Uncertainty Reserve Up Requirement; 10-minute Ramp and Uncertainty Reserve Down Requirement; 30-minute Ramp and Uncertainty Reserve Requirement; 30-minute Reserve Requirement; in the day-ahead energy and reserve markets, the Day-Ahead Scheduling Reserve Requirement; and, in the real-time energy and reserve markets, Regulation Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for 10-minute Ramp and Uncertainty Reserve Down through economic dispatch, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4E 30-minute Ramp and Uncertainty Reserve.

(a) A Market Buyer shall satisfy its 30-minute Ramp and Uncertainty Reserve Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.003. PJMSettlement shall be the Counterparty to the purchases and sales of 30-minute Ramp and Uncertainty Reserve in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain 30-minute Ramp and Uncertainty Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Ramp and Uncertainty Reserve Requirement of the Reserve Zone. The Office of the Interconnection shall

clear both the Day-ahead 30-minute Ramp and Uncertainty Reserve Market and the Real-time 30-minute Ramp and Uncertainty Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the 30-minute Ramp and Uncertainty Reserve Market. Resources eligible to sell 30-minute Ramp and Uncertainty Reserve shall be cleared to provide 30-minute Ramp and Uncertainty Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's 30-minute Ramp and Uncertainty Reserve offer and the product substitution cost of providing 30-minute Ramp and Uncertainty Reserve, energy and any other product the resource is capable of providing; and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement; 10-minute Ramp and Uncertainty Reserve Up Requirement; 10-minute Ramp and Uncertainty Reserve Down Requirement; 30-minute Ramp and Uncertainty Reserve Requirement; 30-minute Reserve Requirement; in the day-ahead energy and reserve markets, the Day-Ahead Scheduling Reserve Requirement; and, in the real-time energy and reserve markets, Regulation Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for 30-minute Ramp and Uncertainty Reserve through economic dispatch, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4F 60-minute Reserve.

(a) A Market Buyer shall satisfy its 60-minute Reserve Obligation at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.004. PJMSettlement shall be the Counterparty to the purchases and sales of 60-minute Reserve in the PJM Interchange Energy Market.

(b) The Office of the Interconnection shall obtain 60-minute Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the Day-Ahead Scheduling Reserve Requirement of the Reserve Zone not otherwise satisfied by resources providing 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve, and Secondary Reserve. The Office of the Interconnection shall clear the Day-ahead 60-minute Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the 60-minute Reserve Market. Resources eligible to sell 60-minute Reserve shall be cleared to provide 60-minute Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's 60-minute Reserve offer and the product substitution cost of providing 60-minute Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement, 10-minute Ramp and Uncertainty Reserve Up Requirement, 10-minute Ramp and Uncertainty Reserve Down Requirement, 30-minute Ramp and Uncertainty Reserve Requirement, 30-minute Reserve Requirement, and Day-Ahead Scheduling Reserve Requirement in the day-ahead energy and reserve markets.

(c) Market Sellers shall exert all reasonable efforts to maintain their ability to operate if called upon, or ensure the operation of, their generation and/or Economic Load Response Participant resources supplying energy 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.

1.11.6 Real-time Energy Market Suspension.

If the Office of the Interconnection declares a Market Suspension (the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour), Real-time Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.5.2 and the Office of the Interconnection shall notify Market Participants of the Market Suspension as soon as practicable.

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 Energy Make Whole 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 Energy Make Whole 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 may 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, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, Secondary Reserve and 60-minute Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule 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. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. 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.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (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 network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. 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 resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Operating Reserve Demand Curves corresponding to each reserve service, and any monitored transmission constraints that may exist.

(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 Operating Agreement, Schedule 1, section 2.4, 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 Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price 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 described in Operating Agreement, Schedule 1, section 2.4 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 an Economic Load Response Participant; (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative inclusive of Transmission Constraint Penalty Factors); associated with increasing the output of a generation resource or decreasing the consumption by an Economic

Load Response Participant, based on the effect of increased generation from the resource on transmission constraints, which may include the modeling of energy and/or reserves, as described in the PJM Manuals; 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 an Economic Load Response Participant Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time 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.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

(e) The Office of the Interconnection shall use its Real-time Price software to calculate the cost of procuring an additional increment of Synchronized Reserve at each bus as the sum of the following components of the Synchronized Reserve Locational Clearing Price: (1) system Synchronized Reserve price, which is the price of supplying an additional increment of Synchronized Reserve in the system; and (2) Synchronized Reserve congestion price at the bus, 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 an Economic Load Response Participant at that bus providing Synchronized Reserve, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact Synchronized Reserve, as described in the PJM Manuals.

(f) The Office of the Interconnection shall use its Real-time Price software to calculate the cost of procuring an additional increment of 10-minute Ramp and Uncertainty Reserve Up at each bus as the sum of the following components of the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price: (1) system 10-minute Ramp and Uncertainty Reserve Up price, which is the price of supplying an additional increment of 10-minute Ramp and Uncertainty Reserve Up in the system; and (2) 10-minute Ramp and Uncertainty Reserve Up congestion price at the bus, 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 an Economic Load Response Participant at that bus providing 10-minute Ramp and Uncertainty Reserve Up, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 10-minute Ramp and Uncertainty Reserve Up as described in the PJM Manuals.

(g) The Office of the Interconnection shall use its Real-time Price software to calculate the cost of procuring an additional increment of 10-minute Ramp and Uncertainty Reserve Down at each bus as the sum of the following components of the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price: (1) system 10-minute Ramp and Uncertainty Reserve Down price, which is the price of supplying an additional increment of 10-minute Ramp and Uncertainty Reserve Down in the system; and (2) 10-minute Ramp and Uncertainty Reserve Down congestion price at the bus, which is the effect on transmission congestion costs (whether positive or negative) associated with decreasing the output of a generation resource or increasing the consumption by an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 10-minute Ramp and Uncertainty Reserve Down, as described in the PJM Manuals.

(h) The Office of the Interconnection shall use its Real-time Price software to calculate the cost of procuring an additional increment of 30-minute Ramp and Uncertainty Reserve at each bus as the sum of the following: (1) system 30-minute Ramp and Uncertainty Reserve price, which is the price of supplying an additional increment of 30-minute Ramp and Uncertainty Reserve in the system; and (2) 30-minute Reserve 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 an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 30-minute Ramp and Uncertainty Reserve, as described in the PJM Manuals. The 30-minute Ramp and Uncertainty Reserve Locational Clearing Price for a given bus shall be the sum of the cost of supplying an additional increment of 30-minute Ramp and Uncertainty Reserve at the bus as described above and the system 30-minute Reserve price as discussed in Operating Agreement, Schedule 1, section 2.5(i).

(i) The Office of the Interconnection shall use its Real-time Price software to calculate the cost of procuring an additional increment of 30-minute Reserve at each bus as the sum of the following components of the Secondary Reserve Locational Clearing Price: (1) system 30-minute Reserve price, which is the price of supplying an additional increment of 30-minute Reserve in the system; and (2) 30-minute Reserve congestion price at the bus, 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 an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 30-minute Reserve, as described in the PJM Manuals.

2.5.1 Prices During Emergency Actions

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a Synchronized Reserve shortage as further described in the PJM Manuals.

(b) If a Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best

available alternate data sources to determine if the Reserve Zone is experiencing a Synchronized Reserve shortage.

(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 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 Voltage Reduction Warning, and Manual Load Dump Warning.

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, the system Synchronized Reserve price referenced in Operating Agreement, Schedule 1, section 2.5(e) shall be equal to the maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service, and the Real-time System Energy Price shall be equal to the sum of (i) the maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service and (ii) $2,000/MWh. The system Synchronized Reserve price and Real-time System Energy Price will continue to be used in the Synchronized Reserve Locational Clearing Price and the Locational Marginal Price calculations, as applicable and consistent with the provisions for determining those prices, 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, the system Synchronized Reserve price referenced in Operating Agreement,

Schedule 1, section 2.5(e) shall be equal to the maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service and the Real-time System Energy Price shall be equal to the sum of (i) the maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service and (ii) $2,000/MWh. The system Synchronized Reserve price and Real-time System Energy Price will continue to be used in the Synchronized Reserve Locational Clearing Price and the Locational Marginal Price calculations, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.5.2 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.11.6, resources will be paid for their energy output and Real-time Prices shall be determined on an hourly basis and applied to each Real-time Settlement Interval in the following manner:

i) If the Market Suspension is less than or equal to six (6) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be the average of Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

ii) If the Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours and there are cleared Day-ahead Prices for the affected Operating Day, then the Real-time Prices associated with such Market Suspension shall be the Day-ahead Prices for each corresponding hour. If no such Day-ahead Prices exist, then the Real-time Prices shall be the average of the Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

iii) If the Market Suspension is greater than twenty-four (24) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be determined based on the construction of an aggregate supply curve.

The aggregate supply curve shall be established as follows:

For online resources operating on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and compensation.

For online resources operating on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension. The selected cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and

compensation.

For available offline resources, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension for the construction of the aggregate supply curve.

The summation of the actual generation MWs for on-line resources will be used as a proxy for demand. The energy component of Locational Marginal Price will be determined hourly from the supply curve at the intersection of supply and demand where the impact of constraints is not considered. The loss and congestion component of Locational Marginal Price will be set to zero dollars per megawatt-hour.

Self-scheduled resources will be included in the supply stack but with a zero dollar per megawatt-hour offer price, and will not be eligible to set price. Off-line resources and resources directed to lower their output to Economic Minimum will not be eligible to set price. Generation resources that may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability will not be eligible to set price.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy and reserves to serve the next increment of load and meet applicable reserve requirements, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, offers for Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, Secondary Reserve, and 60-minute Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

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, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid; (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 an Economic Load Response Participant, based on the effect of increased generation from the resource on any applicable transmission constraints, which may include the modeling of energy and/or reserves, as described in the PJM Manuals; 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 day-ahead 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 resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of procuring an additional increment of Synchronized Reserve at each bus as the sum of the following components of the Synchronized Reserve Locational Clearing Price: (1) system Synchronized Reserve price, which is the price of supplying an additional increment of Synchronized Reserve in the system; and (2) Synchronized Reserve congestion price at the bus, 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 an Economic Load Response Participant at that bus providing Synchronized Reserve, based on the effect of such a change on the applicable transmission constraints modeling the joint flow of energy and Synchronized Reserve as described in the PJM Manuals.

(c) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of procuring an additional increment of 10-minute Ramp and Uncertainty Reserve Up at each bus as the sum of the following: (1) system 10-minute Ramp and Uncertainty Reserve Up price, which is the price of supplying an additional increment of 10-minute Ramp and Uncertainty Reserve Up in the system; and (2) 10-minute Ramp and Uncertainty Reserve Up congestion price at the bus, 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 an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 10-minute Ramp and Uncertainty Reserve Up, as described in the PJM Manuals. The 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price shall be the sum of the cost of supplying an additional increment of 10-minute Ramp and Uncertainty Reserve Up at the bus as described above and the 60-minute Reserve Market Clearing Price.

(d) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of procuring an additional increment of 10-minute Ramp and Uncertainty Reserve Down at each bus as the sum of the following components of the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price: (1) system 10-minute Ramp and Uncertainty Reserve Down price, which is the price of supplying an increment of 10-minute Ramp and Uncertainty Reserve Down in the system; and (2) 10-minute Ramp and Uncertainty Reserve Down congestion price at the bus, which is the effect on transmission congestion costs (whether positive or negative) associated with decreasing the output of a generation resource or increasing the consumption by an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 10-minute Ramp and Uncertainty Reserve Down, as described in the PJM Manuals.

(e) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of procuring an incremental change in the 30-minute Ramp and Uncertainty Reserve service at each bus as the sum of the following: (1) system 30-minute Ramp and

Uncertainty Reserve price, which is the price of supplying an increment of 30-minute Ramp and Uncertainty Reserve in the system; and (2) 30-minute Reserve congestion price at the bus, 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 an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 30-minute Ramp and Uncertainty Reserve, as described in the PJM Manuals. The 30-minute Ramp and Uncertainty Reserve Locational Clearing Price shall be the sum of the cost of supplying an additional increment of 30-minute Ramp and Uncertainty Reserve at the bus as described above, the system 30-minute Reserve price as discussed in Operating Agreement, Schedule 1, section 2.6(f) and the 60-minute Reserve Market Clearing Price.

(f) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of procuring an incremental change in the 30-minute Reserve at each bus as the sum of the following: (1) system 30-minute Reserve price, which is the price of supplying an increment of 30-minute Reserve in the system; and (2) 30-minute Reserve congestion price at the bus, 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 an Economic Load Response Participant at that bus, based on the effect of such a change on the applicable transmission constraints modeling energy and reserves that impact 30-minute Reserve, as described in the PJM Manuals. The Secondary Reserve Locational Clearing Price is the sum of the cost of supplying an additional increment of 30-minute Reserve at the bus as described above and the 60-minute Reserve Market Clearing Price.

(g) The Office of the Interconnection shall use its day-ahead market clearing software to calculate the cost of serving an additional increment of Day-Ahead Scheduling Reserve to the system as the 60-minute Reserve Market Clearing Price.

2.6.1 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.10.8(d), Day-ahead Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Price of zero dollars per megawatt-hour and all settlements will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(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 Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) The Office of the Interconnection's Regulation service is comprised of Regulation-Down Service and Regulation-Up Service. Regulation-Down Service and Regulation-Up Service will have distinct requirements, clearing prices, and performance scores, calculated in accordance with the section(s) below and the PJM Manuals.

Each Market Participant 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-Down Requirement and Regulation-Up Requirement of such Regulation Zone for the hour, based on the Market Participant'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"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market mileage clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources 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 below, the resource-specific shoulder opportunity costs described in subsection (e) of this section, the resource-specific inter-temporal opportunity costs discussed in subsection (d), and the resource-specific opportunity costs discussed in subsection (e) of this section.

(c) The Office of the Interconnection shall commit resources to provide Regulation-Down Service and Regulation-Up Service every 30 minutes, for the clock intervals of the first 30 minutes of an hour and the second 30 minutes of an hour, to meet the Regulation-Down Requirement and Regulation-Up Requirement of such Regulation Zone. The Office of the Interconnection shall select resources in merit order, taking into account the resource's mileage Regulation offer, capability Regulation offer, and estimated resource-specific opportunity cost, all converted into their performance adjusted values as further detailed in the PJM Manuals. The total Regulation market-clearing price for the Regulation-Down Service and Regulation-Up Service in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the mileage 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. A resource's Regulation offer by any Market Seller that fails Regulation the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such

resource, plus six dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the resource-specific opportunity costs (in dollars) of a resource offering to sell Regulation in each regulating interval, except for hydroelectric resources, shall be equal to the area bounded by (i) Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the resource's tracking ramp-rate limited expected output level if it had been dispatched for energy in economic merit order, as further described in the PJM Manuals, and (iv) the resource's regulation set point on the energy schedule curve on which the resource is running in the PJM Interchange Energy Market. The area is divided by the resource performance score and further divided by the resource's regulation assigned megawatt to convert to dollars per megawatt.

For hydroelectric resources offering to sell Regulation in a regulating interval, 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 Real-time Settlement Intervals 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 Real-time Settlement Interval.

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 Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or

off-peak period, excluding those Real-time Settlement Intervals 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 the average of the Locational Marginal Price values used in the calculation for 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 the average of the Locational Marginal Price used in the calculation for opportunity costs for hydroelectric resources.

Opportunity costs for Economic Load Response Participant resources and regulation-only resources to provide Regulation are zero for the purpose of committing resources, setting Regulation clearing prices, and settlements.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the Office of the Interconnection shall consider both the Regulation-Up Service and Regulation-Down Service selected MW assignments. The unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the two Real-time Settlement Intervals preceding the regulation commitment and the two Real-time Settlement Intervals following the regulation commitment in accordance with the PJM Manuals and below.

The unit-specific opportunity cost in dollars incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource’s Final Offer, (iii) the generation resource’s tracking ramp rate limited expected output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the generation resource’s regulation set point, and adjusted for the performance score of the resource offset by the regulation signal bias, and adjusted for the performance score of the resource. Opportunity costs for Economic Load Response Participant or regulation only resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding two Real-time Settlement Intervals of the regulation commitment 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 Real-time Settlement Interval in order to provide Regulation and the resource’s tracking expected ramp rate limited output in each of the preceding two Real-time Settlement Intervals of the regulation commitment times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval in the PJM Interchange Energy Market, 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 each of the following two Real-time Settlement Intervals of the regulation commitment 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 Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp-rate limited output in each of the following two Real-time Settlement Intervals of the regulation commitment times, and (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in final regulating hour, in the PJM Interchange Energy Market 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 prices in that hour shall be allocated and charged to each Market Participant 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 Regulation market mileage-clearing price for Regulation-Down Service and Regulation-Up Service, the Office of the Interconnection shall adjust the submitted applicable mileage offer for each resource in accordance with the historical performance score of that resource, and the amount of historically dispatched Regulation (mileage) for the given service, calculated by the Office of the Interconnection. The maximum adjusted mileage offer of all cleared resources for each regulation service will set the Regulation market mileage-clearing price for Regulation-Down Service and Regulation-Up Service.

The owner of each Regulation resource that is committed for a regulation service and actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation-Down Service and/or Regulation-Up Service mileage by multiplying the applicable regulation service assigned MW(s) by the applicable regulation service Regulation market mileage-clearing price, by the ratio between the requested mileage for the Regulation service dispatch signal and the historic requested mileage for the applicable Regulation service dispatch signal, calculated by the Office of the Interconnection, and by the Regulation resource's applicable regulation service performance score calculated in accordance with subsection (j) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer for Regulation-Down Service or Regulation-Up Service by the applicable regulation service historic performance score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for Regulation-Down Service and Regulation-Up Service for each Regulation Zone by

subtracting the applicable regulation service Regulation market mileage-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for the Regulation-Down Service and Regulation-Up Service Real-time Settlement Interval.

The owner of each Regulation resource that is committed for a regulation service and actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation-Down Service and Regulation-Up Service capability by multiplying the applicable regulation service assigned MW and the applicable regulation service capability Regulation market-clearing price multiplied by the Regulation resource's applicable regulation service performance score calculated in accordance with subsection (j) 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 each Regulation resource's performance score for Regulation-Down Service and Regulation-Up Service. The performance score shall be 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 error measured shall be the difference of the resources response and the dispatch signal, adjusted by the assigned MW and signal dispatch of the Regulation resource. The performance score is calculated using the following equations:

Performance Score = $1 - 1/n \sum$ Abs (Error);

Error = Average of Abs (Abs (Response - Regulation Signal) / (0.5*Interval Average Regulation Signal + 0.5*AREG)); and

n = the number of samples in the interval
AREG = assigned regulation megawatt.

The Office of the Interconnection shall calculate a performance score for each Regulation resource for each regulation service for each five-minute period the Regulation resource is assigned to provide Regulation-Down Service and/or Regulation-Up Service.

The historic performance score for Regulation-Down Service and Regulation-Up Service will be based on a 100 clock-hour rolling average of the Real-time Settlement Interval performance scores, with consideration of the qualification score, for resources without adequate historical data, as defined in the PJM Manuals.

Regulation resources that have a Real-time Settlement Interval performance score below 25% will be ineligible for Regulation credits for that Real-time Settlement Interval.

Regulation resources that have historical performance scores fall below 40% shall be disqualified from providing the applicable Regulation service until they are able to re-qualify, as defined in the PJM Manuals.

(k) During a Market Suspension where the suspension is less than or equal to 24 consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than 24 consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their adjusted Regulation offer and adjusted opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.

For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation performance score cannot be calculated during a Market Suspension, the historic performance score will be used for the Market Suspension period.

(ii) If the regulation mileage cannot be calculated during a Market Suspension, the mileage will be set to one (1) for the Market Suspension period.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) For each Regulation market clearing interval, the Office of the Interconnection shall conduct a Regulation three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the Regulation three-pivotal supplier test shall be capped in the interval in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any Regulation market clearing interval in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal. The Regulation three-pivotal supplier test will be conducted separately for Regulation-Down Service and Regulation-Up Service in the same Regulation market clearing interval.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The Regulation three-pivotal supplier test will include in the definition of available supply all offer megawatts from resources capable of satisfying the Regulation-Down Requirement and Regulation-Up Requirement of the PJM Region multiplied by the historic performance score of the resource for which the capability cost-based offer plus the mileage cost-based offer plus any eligible opportunity costs is no greater than 150% of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The Regulation 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. 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 Regulation clearing interval to determine the residual supply index. Where the residual supply index for

Regulation 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 Energy Uplift.

(a) A Market Seller's pool-scheduled resources shall be credited as specified below for Energy Make Whole credits.

(b) Day-ahead Energy Make Whole credits shall be calculated in the following manner for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs 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) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as day-ahead Energy Make Whole credits.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Energy Make Whole credit shall be reduced by the greater of zero or the difference of the resource's day-ahead Energy Make Whole target and the balancing Energy Make Whole target, as determined below.

A resource's day-ahead Energy Make Whole target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's balancing Energy Make Whole target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the Real-time Cost, as defined in subsection 3.2.3(e-2)(ii) of this section, summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead Energy Make Whole target, summed over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled; and

F = the sum of all Other Market Revenues, as defined in subsection 3.2.3(e-2)(ii) of this section, over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled.

(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 Operating Agreement, Schedule 1, section 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 Energy Make Whole credits in the Day-ahead Energy Market.

(d) The cost of Energy Make Whole credits 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), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; 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 Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Energy Make Whole credits 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 Tariff, Schedule 6A. The cost of Energy Make Whole credits 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) 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) (i) Pool-scheduled generation resources that operate for at least one Real-time Settlement Interval within the pool-scheduled commitment period are eligible for balancing Energy Make Whole credits as further detailed in this section and in the PJM Manuals. Balancing Energy Make Whole credits eligibility for Economic Load Response Participant resources is detailed in Operating Agreement, Schedule 1, section 3.2.3(o-1) of this section. A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of:

1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable

or

2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.

Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs. The pre-commitment period begins with the Real-

time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment. However, a generation resource is only eligible for this pre-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the pre-commitment period, are less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the first hour of the commitment. Generation resource types with a soak process in the Start-up Cost are not eligible during the pre-commitment period.

Pool-scheduled generation resources that are released by the Office of Interconnection and ramping offline are additionally eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval that the generation resource goes offline; however, eligibility shall not extend beyond the Real-time Settlement Interval in which the resource is no longer running under the direction of the Office of Interconnection plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource type, as specified in the PJM Manuals. However, a generation resource is only eligible for this post-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the post-commitment period, is less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the last hour of the commitment.

(ii) The balancing Energy Make Whole credit calculation will be conducted on a segmented basis. For each Operating 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.

The first Segment will be defined as the greater of the applicable day-ahead commitment and Minimum Run Time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources).

Further, if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection.

The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.

Notwithstanding the foregoing, each Segment shall be limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

(iii) If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to the Office of the Interconnection committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration. A generation resource that is the subject to an offer parameter on a parameter-limited schedule that exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.

A Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive energy uplift credits 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 the 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 energy uplift credits 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.

(iv) Nuclear generation resources shall not be eligible for energy uplift 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 Operating Agreement, Schedule 1, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. 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.

(e-1) The Tracking Ramp Limited Desired (TRLD) metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by the Office of the Interconnection. There are two Tracking Ramp Limited Desired metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described

below and as further detailed in the PJM Manuals. The Tracking Ramp Limited Desired MWh (energy) calculated for each Real-time Settlement Interval shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. The Tracking Ramp Limited Desired MWh (energy) value represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval.

For purposes of this Operating Agreement, Schedule 1, section 3.2.3, the minimum operating limit used herein shall be the Economic Minimum unless the Office of the Interconnection has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum. Also, the maximum operating limit shall be the Economic Maximum unless the Office of the Interconnection has declared Maximum Emergency conditions, in which case it shall be the emergency maximum.

(i) Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions.

The Tracking Ramp Limited Desired MW (power) calculation starts at time t_0, which is when a generation resource is first expected by the Office of Interconnection to be online or when a generation resource is dispatchable, while honoring soak time differences, as further detailed in the PJM Manuals.

The Tracking Ramp Limited Desired MW (power) metric will be calculated as follows. For the Real-time Settlement Interval equal to t_0,

If a generation resource does not have a soak process and is directed to come online as soon as possible,

TRLD MW (power) = 0

Otherwise,
TRLD MW (power)
= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum]

Where:

LMP Desired MW = the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point

Dispatch MW = energy dispatch signal MW from the dispatch run

Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Operating Agreement, Schedule 1, section 3.2.3(e-1), unless any of the following conditions occur,

- If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.

For each Real-time Settlement Interval after the resource's initial start time, t_0, Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{TRLD MW}_t \text{ (power)} = \text{TRLD MW}_{t-1} \pm \text{Ramp}_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting of the following parameters among the ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum, where:

Tracking Desired Economic Minimum = defined above in the calculation for TRLD MW_{t0}

Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:

- If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.

The Tracking Ramp Limited Desired MW (power) value will be further adjusted, as specified below, if the resource has a regulation or reserve assignment and is unable to

provide such assignment while generating the initial Tracking Ramp Limited Desired MW due to the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is above the highest MW point at which the resource can provide the Regulation or reserve assignments, the Tracking Ramp Limited Desired MW will be lowered to the highest point at which it can provide the assignment(s) based on the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is below the lowest MW point at which the resource can provide the Regulation assignment or reserve assignments, the Tracking Ramp Limited Desired MW will be increased to the lowest point at which it can provide the regulation assignment or reserve assignments based on the resource's applicable operating parameters.

This adjusted Tracking Ramp Limited Desired MW value is used in calculating the Tracking Ramp Limited Desired MW (power) for subsequent intervals.

(ii) An unadjusted Tracking Ramp Limited Desired MW (power) that excludes the impact of Regulation and reserve assignments or manual dispatch instructions is also calculated for conversion to an unadjusted Tracking Ramp Limited Desired MWh (energy) metric which is used in the Other Market Revenue and Company Responsible Negative Reserve Revenues calculations described in subsection 3.2.3(e-2)(i). The unadjusted Tracking Ramp Limited Desired MW (power) metric will be calculated as follows.

For the Real-time Settlement Interval equal to t_0, the unadjusted Tracking Ramp Limited Desired MW (power) equals the Tracking Ramp Limited Desired MW $(\text{power})_{t0}$ as calculated in subsection (i) directly above excluding the impact of regulation and reserve assignments or manual dispatch instructions.

For each Real-time Settlement Interval after the start time, t_0, the unadjusted Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{unadjusted TRLD MW}_t \text{ (power)} = \text{unadjusted TRLD MW}_{t-1} \pm \text{Ramp}_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the unadjusted economic minimum, and the unadjusted economic maximum, where:

unadjusted economic minimum = minimum operating limit for the Real-time Settlement Interval unless such minimum operating limit increased by more than 5% of the resource's minimum operating limit at the time of commitment, in which case the minimum operating limit at the time of commitment shall be used.

unadjusted economic maximum = maximum operating limit for the Real-time Settlement Interval unless such maximum operating limit decreased by more than 5% of the resource's maximum operating limit at the time of commitment, in which case the maximum operating limit at the time of commitment shall be used.

(iii) The Tracking Ramp Limited Desired MW (power) calculations in Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii) above will continue until the resource goes offline; however, if a generation resource trips or is taken offline at the request of the Market Seller prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the values will continue to be calculated per the calculations defined above until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time.

Further, once the Office of the Interconnection releases a generation resource to go offline, provided that the resource actually goes offline following such direction, the Tracking Ramp Limited Desired MW shall be calculated using only the ramp down parameters such that the Tracking Ramp Limited Desired MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. During this time period, the unadjusted Tracking Ramp Limited Desired MW (power) will equal the Tracking Ramp Limited Desired MW (power) unless the resource has been manually dispatched offline, in which case the unadjusted Tracking Ramp Limited Desired MW (power) will continue as specified above in Operating Agreement, Schedule 1, section 3.2.3(e-1)(ii) until the manual dispatch instruction ends.

TRLD MW_t (power) =

Max (TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

(iv) The Tracking Ramp Limited Desired MW (power) and unadjusted Tracking Ramp Limited Desired MW (power) metrics will be converted to the Tracking Ramp Limited Desired MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. For all Real-time Settlement Intervals prior to the start time of the Tracking Ramp Limited Desired MW (power) calculations, t_0 as defined above, both the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to the resource's Actual MWh for that Real-time Settlement Interval. For purposes

of this section, Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

For each Real-time Settlement Interval after the Office of the Interconnection releases a generation resource to go offline and the resource's Actual MWh is below the minimum operating limit, the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to Actual MWh of the resource.

For all other Real-time Settlement Intervals, the Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals. The unadjusted Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-Time Settlement Interval based on the unadjusted Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals.

(v) The Tracking Ramp Limited Desired MW (power) and MWh (energy) values described above in subsections Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii), as may be qualified by (iii), and (iv) of this section may be further adjusted as described in the PJM Manuals to account for instances where the Office of the Interconnection is unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other abnormal dispatch scenarios.

(e-2) For generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Operating Agreement, Schedule 1, section 3.2.3(m). Balancing Energy Make Whole credits for Economic Load Response Participant resources shall be equal to the credits as determined in Operating Agreement, Schedule 1, section 3.3.A.

(i) Step 1: Calculate Tracking Balancing Energy Make Whole credit for the Segment using Tracking Ramp Limited Desired MWh.

Tracking Balancing Energy Make Whole Credit = A – B

Where
$A = -1 \times \sum_t$ Tracking Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

The Tracking Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ - Company Responsible Negative Reserve Revenues$_t$) - Real-time Cost$_t$

Where

t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation:

(Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Energy Revenues

Where: Company Responsible Negative Energy Revenues = any negative balancing energy revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + 10-min RUR Up + 10-min RUR Down + 30-min RUR + 60-minute Reserve + Reserve Uplift – Reserve Offer + Reactive + LOC + Reg

Where

SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A(b)(i) and (b)(ii).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A.01(b)(i) and (b)(ii).

10-minute RUR Up = any potential amounts credited for providing 10-minute Ramp and Uncertainty Reserve Up as specified in Operating Agreement, Schedule 1, section 3.2.3A.001(b)(i) and (b)(ii).

10-minute RUR Down = any potential amounts credited for providing 10-minute Ramp and Uncertainty Reserve Down as specified in Operating Agreement, Schedule 1, section 3.2.3A.002(b)(i) and (b)(ii).

30-minute RUR = any potential amounts credited for providing 30-minute Ramp and Uncertainty Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.003 (b)(i) and (b)(ii).

60-minute Reserve = any amounts credited for providing 60-minute Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.004(b).

Reserve Uplift = any potential reserve market uplift credit as specified in Operating Agreement, Schedule 1, section 3.2.3A.03.

Reserve Offer = any Secondary Reserve offer price, in dollars, plus any Synchronized Reserve offer price, in dollars, included in the resource's potential uplift credit as specified in Operating Agreement, Schedule 1, section 3.2.3A.03(b).

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Operating Agreement, Schedule 1, section 3.2.2.

Company Responsible Negative Reserve Revenues = the sum of the potential company responsible negative reserve revenues as determined in accordance with 3.2.3A.03(i)

For the purposes of the above Other Market Revenue and Company Responsible Negative Reserve Revenues calculations, the potential credits and costs are determined using the calculations referenced above and the assumption that the resource was increased or decreased from the unadjusted Tracking Ramp Limited Desired MWh in

order to provide the assignment or PJM directed MW as further described in the PJM Manuals.

Real-time Cost = (Incremental Offer + No Load Cost + Start-Up Cost)
Where

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Tracking Ramp Limited Desired MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is a Real-time Settlement Interval in the first Segment

The offer used for calculating Real-time Cost shall be the lesser of the Committed Offer or Final Offer based on the offer with the lowest total cost for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the Tracking Ramp Limited Desired MWh (energy) at the minimum operating limit for such interval.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Tracking Ramp Limited Desired MWh (energy) indicate the unit is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.

(ii) Step 2: Calculate balancing Energy Make Whole credits for the Segment using Actual MWh.

Actual Balancing Energy Make Whole Credit = A – B

Where
A = $-1 \times \sum_t$ Actual Balancing Net Revenue$_t$
Where t = the eligible Real-time Settlement Intervals in the applicable Segment
B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

The Actual Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation. For purposes of this section, the Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A.

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:
Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

(Actual MWh – Day-ahead Scheduled MWh) × Real-time LMP ― Company Responsible Negative Energy Revenues

Where: Company Responsible Negative Energy Revenues = any negative balancing energy revenues in excess of the DA revenue based on the Market Participant's actions reducing flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ― Real-Time LMP, 0)

Other Market Revenue = SR + SecR + 10-min RUR Up + 10-min RUR Down + 30-min RUR + 60-minute Reserve + Reserve Uplift – Reserve Offer – Reserve Charges + Reactive + LOC + Reg

Where:

SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Operating Agreement, Schedule 1, section 3.2.3A(b)(i) and (b)(ii) .

SecR = any amounts credited for providing Secondary Reserve as determined in Operating Agreement, Schedule 1, section 3.2.3A.01 (b)(i) and (b)(ii).

10-minute RUR Up = any amounts credited for providing 10-minute Ramp and Uncertainty Reserve Up as determined in Operating Agreement, Schedule 1, section 3.2.3A.001(b)(i) and (b)(ii).

10-minute RUR Down = any amounts credited for providing 10-minute Ramp and Uncertainty Reserve Down as specified in Operating Agreement, Schedule 1, section 3.2.3A.002(b)(i) and (b)(ii).

30-minute RUR = any amounts credited for providing 30-minute Ramp and Uncertainty Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.003 (b)(i) and (b)(ii).

60-minute Reserve = any amounts credited for providing 60-minute Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.004(b).

Reserve Uplift = any reserve market uplift credit as specified in Operating Agreement, Schedule 1, section 3.2.3A.03(b).

Reserve Charges = the positive value of any reserve unavailability charges as specified in Operating Agreement, Schedule 1, sections 3.2.3A(m), 3.2.3A.001(h), 3.2.3A.002(e), 3.2.3A.003(e), 3.2.3A.004(f), and reserve non-performance charges as specified in 3.2.3A(j), 3.2.3A.004(e), and 3.2.3A.01(h). This value is capped at the revenues the resource received in the relevant reserve market, as further specified in the PJM manuals.
Reserve Offer = any Secondary Reserve offer price, in dollars, plus any Synchronized Reserve offer price, in dollars, included in the resource's uplift credit as specified in Operating Agreement, Schedule 1, section 3.2.3A.03(b).

Reactive = any amounts credited for providing Reactive Services as determined in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Operating Agreement, Schedule 1, section 3.2.2

Real-time Cost = (Incremental Offer + No Load + Start-Up)

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Actual MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is within the first Segment

The offer used for calculating Real-time Cost shall be the Final Offer for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Actual MWh indicate the resource is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable by the Office of the Interconnection since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.

(iii) In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits. If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.

(iv) A price-sensitive pool-scheduled import transaction shall receive balancing Energy Make Whole credits equal to the positive difference between a transaction's offer, and the total value of the transaction's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations from the Day-ahead Energy Market at the real-time LMP(s) applicable to the sink of the transaction summed over all Real-time Settlement Intervals in the Operating Day.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 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 for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource 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 in section 3.2.3(f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), 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 Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals 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 of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 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 of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource Model Participant 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 or solar generating units, Hybrid Resource or Energy Storage Resource Model Participant 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 , 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 for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to increase charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, shall be compensated for the increase in charging in the same manner as provided in sections 3.2.3(e). A unit in the Energy Storage Resource Participation Model or a Hybrid Resource instructed to reduce

charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, is not eligible for compensation under section 3.2.3(f-4).

(f-5) If a Market Participant of an Energy Storage Resource Model Participant or a Hybrid Resource believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. 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 Participant 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f) through Operating Agreement, Schedule 1, section 3.2.3(f-5), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, 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, plus any balancing Energy Make Whole Credits paid to pool-scheduled import transactions, less any payments received from another Control Area for energy uplift shall be allocated to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region, determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate the charges to the pro rata share of the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of

energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(h) Each Market Participant's daily total of hourly deviations are determined in accordance with the following equation:

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations under this subsection (h).

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval 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, which include the components referenced in Operating Agreement, Schedule 1, section 3.2.3(d) regarding the cost of Energy Make Whole credits in the Day-ahead Energy Market, 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 charges in the event of a Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a 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.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of supply or demand deviations.

Deviations as calculated above shall be deviations in the RTO region and shall be subject to charges for the RTO region determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Furthermore, deviations that occur within a single Zone shall be associated with the Eastern or Western region, as defined in Operating Agreement, Schedule 1, section 3.2.3(q) below, and shall be subject to charges determined for such region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). 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 charges determined for such region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). 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.

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary 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, Secondary 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 energy uplift for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary 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 energy uplift for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary 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 Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, 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 an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Energy Make Whole 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 Operating Agreement, Schedule 2, 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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, 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 Energy Make Whole. 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 Energy Make Whole for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The

Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals 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 Real-time Settlement Intervals 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 11:00 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 Energy Make Whole. If notice of a MaxGen Condition is provided after 11:00 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 Energy Make Whole 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 Energy Make Whole 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 Energy Make Whole 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 Energy Make Whole 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 Energy Make Whole 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) All generation resources shall be assessed deviations in accordance with the calculations described below and in the PJM Manuals.

Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and

Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).

$$Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ \ MWh}]$$

If the Actual MWh is equal to zero, the deviation percentage is equal to 1 (100 percent).

Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur:

- The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as intervals when the minimum operating limit is equal to the maximum operating limit, or intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals. All hydro resources are considered non-dispatchable unless operated as a dispatchable resource by the Office of the Interconnection.
- The self-scheduled generation resource is not dispatchable due to a limited dispatchable range. A dispatchable range is considered limited when the following equation is true:
    - Abs(maximum operating limit – minimum operating limit) <= 10% of Abs(minimum operating limit).
- The dispatchable self-scheduled generation resource has a Tracking Ramp Limited Desired MWh <= the minimum operating limit, except when the resource is desired at that level due to a Minimum Generation Emergency declaration or event.
- A generation resource is online and Tracking Ramp Limited Desired MWh is unable to be calculated due to unavailable schedules or offer parameters.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its day-ahead deviation percentage is <= 0.05 (5%).

$$Day-ahead\ Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}]$$

If the Actual MWh is equal to zero, the day-ahead deviation percentage is equal to 1 (100 percent).

A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:

- The resource is assigned pool-scheduled Regulation.
- The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Secondary Reserves.
- The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.
- Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.
- The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.

Deviations of generation resources with multiple units located at a single bus shall be netted for each Real-time Settlements Interval as described in Operating Agreement, Schedule 1, section 3.2.3(h)(i).

If a resource has an hourly average of the absolute value of generator deviations that is less than 5 MWh, then the resource shall not be assessed deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.

For the purpose of this section 3.2.3(o), a generation resource is considered to be following dispatch if it is not assessed deviations or has a deviation equal to zero in a Real-time Settlement Interval, as determined above and prior to any netting pursuant to section 3.2.3(h)(i) or for hourly averages pursuant to this section

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed deviations. Economic load reduction resources that do not follow dispatch shall be assessed 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 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 deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity) and charged as defined in Operating Agreement, Schedule 1, section 3.3A. 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 Operating Agreement, Schedule 1, section 3.3A. 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 apply any balancing Energy Make Whole credits determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(e-2), except those associated with the scheduling of units for Black Start Service or testing of Black Start Service units as provided in Tariff, Schedule 6A, to deviations determined pursuant to section 3.2.3(h) or real-time load plus exports depending on whether the underlying balancing Energy Make Whole 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 Energy Make Whole 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 Energy Make Whole credits, identified as reliability analysis credits for deviations, shall be allocated to deviations determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).

(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 Energy Make Whole credits, identified as reliability analysis 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 Energy Make Whole credits shall be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(p)(i)(A) and 3.2.3(p)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Energy Make Whole 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 Energy Make Whole credits, identified as real-time 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 exceeds 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 (real-time credits for reliability or real-time 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 Operating Agreement, Schedule 1, section 3.2.3(p)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Energy Make Whole credits, identified as real-time credits for deviations, shall be allocated to deviations determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in Operating Agreement, Schedule 1, sections 3.2.3(p)(i) and (p)(ii).

The costs associated with scheduling of units for Black Start Service or testing of Black Start Service units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zonal load or non-Zonal load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

(q) (i) Balancing Energy Make Whole credits for reliability or deviations as determined in Operating Agreement, Schedule 1, section 3.2.3(p) shall be assigned to the Eastern or Western region if the credit paid to the generator is due to transmission constraints that occur on transmission system capacity equal to or less than 345kv. Balancing Energy Make Whole credits for reliability or deviations not assigned to the Eastern or Western region shall be assigned to the RTO region. For the purposes of this section, the Western region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones.

(ii) The total balancing Energy Make Whole credits for reliability in each region shall be allocated as charges to each Market Participant's pro rata share of real-time load plus export transactions in such region. For purposes of this Operating Agreement, Schedule 1, section 3.2.3(q), a Market Participant's real-time load plus export transactions shall be equal to the daily total of (i) real-time deliveries of energy to load in the relevant region ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy), served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) real-time deliveries of energy sales from within the PJM Region to load outside the PJM Region in megawatt-hours during that Operating Day, but not including its bilateral transactions that

are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(iii) The total balancing Energy Make Whole credits for deviations in the Eastern region and the Western region shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the relevant region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). The total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(ii).

(q-1) (i) Regional balancing uplift rates shall be determined in accordance with the following provisions:

The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western regions. Regional adder rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the region divided by the total real-time load plus export transactions in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(ii). Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p).

Regional adder rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the region divided by the daily total of hourly deviations in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii).

(ii) The Office of the Interconnection shall calculate RTO balancing uplift rates. RTO balancing uplift rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the RTO region divided by the total real-time load plus export transactions in the RTO region in accordance with section (q)(ii). RTO balancing uplift rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) divided by the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). Whether the underlying credits are allocated as reliability or deviation charges

shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p).

(iii) Reliability and deviation regional balancing uplift rates shall be determined by summing the relevant RTO balancing Energy Make Whole rates and regional adder rates.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Energy Make Whole 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, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any Energy Make Whole credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Market Participants shall have an obligation for Synchronized Reserve based on the quantity of Synchronized Reserve procured for the Reserve Zone. A Market Participant's obligation to pay for Synchronized Reserve shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus exports for the Real-time Settlement Interval ("Synchronized Reserve Obligation").A Market Participant with a Synchronized Reserve Obligation shall be charged their pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve for each Real-time Settlement Interval as defined in sections 3.2.3A(b)(i) and (ii) below .

(b) Resources assigned to provide Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Locational Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide for the hour. When calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized

Reserve Market shall be determined for each Real-time Settlement Interval based on the deviations determined in accordance with the following equation:

(A - B) * C

Where:

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market.

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Locational Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Resources pool-scheduled to provide Synchronized Reserve shall be credited a reserve uplift credit as described in section 3.2.3A.03 below.

(c) [Reserved for future use]

(d) Synchronized Reserve Locational Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Locational Clearing Price shall be determined for each bus by the Office of the Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Locational Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Locational Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Locational Clearing Price shall be determined for each bus by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.5..

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Locational Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Locational Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Locational Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Locational Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Locational Clearing Prices exist, then the Synchronized Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Locational Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for any necessary uplift costs via the reserve uplift credit calculated in section 3.2.3A.03 below using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in the Reserve 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 Real-time Synchronized Reserve Locational Clearing

Price shall be calculated in accordance with Operating Agreement, Schedule 1, section 2.5.1.
s

(iii) For purposes of settlements, the Synchronized Reserve Locational Clearing Price shall be floored at $0/MWh.

(e) For determining the Synchronized Reserve Locational Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. 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 energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead 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. 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 energy commitment greater than zero shall be zero.

(f) [Reserved for future use]
(g) [Reserved for future use]

(h) For each Real-time Settlement Interval, a share of the sum of the reserve uplift credits calculated in accordance with section 3.2.3A.03 below shall be allocated and charged to each Market Participant that does not meet its Synchronized Reserve Obligation through self-scheduling Synchronized Reserve based upon its real-time purchases of Synchronized Reserve in megawatt-hours during that interval as further described in Operating Agreement Schedule 1 section 3.2.3A.03(j). For this purpose, a Market Participant's real-time purchases of Synchronized Reserve shall be equal to their Synchronized Reserve Obligation as calculated in subsection (a) above minus any MW the participant self-scheduled to provide Synchronized Reserve.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be assessed a Synchronized Reserve non-performance charge at the Synchronized Reserve non-performance charge rate for each increment of performance shortfall as measured in accordance with this Operating Agreement, Schedule 1, section 3.2.3A(k)-(l) in excess of five percent of the amount of real-time Synchronized Reserve the resource was directed to deploy. The performance shortfall is measured as the real-time Synchronized Reserve the resource was directed to deploy minus the amount that actually responded for all Real-time Settlement

Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. The determination of the amount of Synchronized Reserve response credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The Synchronized Reserve non-performance charge rate for a Synchronized Reserve Event shall be the higher of (i) the highest Real-time System Energy Price in the next 6 intervals following the initiation of the event and (ii) the annual average cost of Synchronized Reserve procurement. In no case shall the Synchronized Reserve non-performance charge rate be less than $0/MWh or greater than the maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service.

The annual average cost of Synchronized Reserve procurement for purposes of this calculation shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average cost of Synchronized Reserve procurement shall be effective as of the following January 1.

The average cost of Synchronized Reserve procurement for the subject year shall be calculated as A * B * 24 hours/day, where:

A = the average number of days between Synchronized Reserve Events (in days) for the subject year, rounded down to a whole day value, where the whole day value shall not exceed the number of days in the year.

B = the average Real-time Synchronized Reserve Locational Clearing Price for the subject year.

The Synchronized Reserve Event non-performance charges shall be allocated as credits to Market Participants based on their pro rata share of the Synchronized Reserve Obligation megawatts in the Real-time Settlement Intervals(s) of the Synchronized Reserve Event for the Reserve Zone, except that Market Participants that incur a Synchronized Reserve non-performance charge and also have an applicable Synchronized Reserve Obligation during the Real-time Settlement Intervals of the Synchronized Reserve Event shall not be included in the allocation of such credits. If the event spans multiple hours, the 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 an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the

generation resource's output or the Economic Load Response Participant 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 Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant 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 an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant 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.

(m) A generation resource or Economic Load Response Participant Resource that has been assigned to provide Synchronized Reserve in real-time but fails to maintain availability commensurate with this assignment as described in the PJM Manuals will be subject to an unavailability charge unless a Synchronized Reserve Event is in effect and the resource has been directed to deploy Synchronized Reserve. The unavailability charge shall be the amount of Real-Time Synchronized Reserve capability that was not maintained for each Real-time Settlement Interval at a rate equal to the greater of (i) 1.25 times the Real-time Synchronized Reserve Locational Clearing Price and (ii) the per megawatt cost for the resource to provide the assigned Synchronized Reserves (inclusive of Synchronized Reserve offer cost, real-time opportunity costs, and the cost of buying out of the resource's Synchronized Reserve assignment in the Day-ahead Market as further described in the PJM Manuals). In no event shall this rate be less than $0/MWh.

The charges assessed to resources that fail to maintain availability of the assigned Real-Time Synchronized Reserves for a Real-time Settlement Interval shall be allocated as credits to Market

Participants based on their pro rata share of the Synchronized Reserve Obligation megawatts in that interval, except that Market Participants that incur a charge for failure to maintain availability of these reserves in the given interval and also have an applicable Synchronized Reserve Obligation shall not be included in the allocation of such credits.

3.2.3A.001 10-minute Ramp and Uncertainty Reserve Up.

(a) Market Participants shall have an obligation for 10-minute Ramp and Uncertainty Reserve Up based on the quantity of 10-minute Ramp and Uncertainty Reserve Up procured for the Reserve Zone. A Market Participant's obligation to pay for 10-minute Ramp and Uncertainty Reserve Up shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus exports for the Real-time Settlement Interval ("10-minute Ramp and Uncertainty Reserve Up Obligation"). A Market Participant with a 10-minute Ramp and Uncertainty Reserve Up Obligation shall be charged their pro rata share of the sum of day-ahead and real-time credits for 10-minute Ramp and Uncertainty Reserve Up for each Real-time Settlement Interval as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide 10-minute Ramp and Uncertainty Reserve Up at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for 10-minute Ramp and Uncertainty Reserve Up provided by generation resources and Economic Load Response Participant resources assigned to provide 10-minute Ramp and Uncertainty Reserve Up by the Office of the Interconnection in the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Market shall be equal to the product of the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price multiplied by the megawatt amount of 10-minute Ramp and Uncertainty Reserve Up such resource is assigned to provide for the hour. When calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

(ii) Credits for 10-minute Ramp and Uncertainty Reserve Up provided by generation resources and Economic Load Response Participant resources assigned to provide 10-minute Ramp and Uncertainty Reserve Up by the Office of the Interconnection in the Real-time 10-minute Ramp and Uncertainty Reserve Up Market shall be determined for each Real-time Settlement Interval based on their Real-time Settlement Interval deviations determined in accordance with the following equation:

(A - B) * C

Where:

A = For each Real-time Settlement Interval, the megawatts of 10-minute Ramp and Uncertainty Reserve Up from that resource assigned by the Office of the Interconnection in the Real-time 10-minute Ramp and Uncertainty Reserve Up Market;

B = For each Real-time Settlement Interval, the megawatts of 10-minute Ramp and Uncertainty Reserve Up from that resource assigned by the Office of the Interconnection in the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Market; and

C = For each Real-time Settlement Interval, the Real-time 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price.

(iii) Resources pool-scheduled to provide 10-minute Ramp and Uncertainty Reserve Up shall be credited a reserve uplift credit as determined in accordance with section 3.2.3A.03 below.

(c) 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices

(i) For the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Market, the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price shall be determined for each bus by the Office of the Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time 10-minute Ramp and Uncertainty Reserve Up market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time 10-minute Ramp and Uncertainty Reserve Up Market, the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price shall be determined for each bus by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.5.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning 10-minute Ramp and Uncertainty Reserve Up, then the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning 10-minute Ramp and Uncertainty Reserve Up, then the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices associated with such Market Suspension shall be the average of the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices for the affected Operating Day, then the Real-time 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices associated with such Market Suspension shall be the Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices for each corresponding hour. If no such Day-ahead 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices exist, then the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices associated with such Market Suspension shall be the average of the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning 10-minute Ramp and Uncertainty Reserve Up. Resources will be compensated for any necessary uplift costs via the reserve uplift credits calculated in section 3.2.3A.03 below using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

(iii) For purposes of settlements, the 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price shall be floored at $0/MWh.

(d) [Reserved for future use]

(e) [Reserved for future use]

(f) For each Real-time Settlement Interval, a share of the sum of the reserve uplift credits calculated in accordance with section 3.2.3A.03 below shall be allocated and charged to each Market Participant with an10-minute Ramp and Uncertainty Reserve Up Obligation for the Real-time Settlement Interval as further described in section 3.2.3A.03(j) below.

(g) [Reserved for future use]

(h) A generation resource or Economic Load Response Participant Resource that has been assigned to provide 10-minute Ramp and Uncertainty Reserve Up by the Office of the Interconnection in real-time but fails to maintain availability commensurate with this assignment as described in the PJM Manuals will be subject to an unavailability charge unless a Synchronized Reserve Event is in effect and the resource has been directed to deploy Synchronized Reserve. The unavailability charge shall be the amount of Real-Time 10-minute Ramp and Uncertainty Reserve Up capability that was not maintained for each Real-time Settlement Interval at a rate equal to the greater of (i) 1.25 times the Real-time 10-minute Ramp and Uncertainty Reserve Up Locational Clearing Price and (ii) the per megawatt cost for the resource to provide the assigned 10-minute Ramp and Uncertainty Reserve Up (inclusive of real-time opportunity costs and the cost of buying out of the resource's 10-minute Ramp and Uncertainty Reserve Up assignment in the Day-ahead Market as further described in the PJM Manuals). In no event shall this rate be less than $0/MWh.

The charges assessed to resources that fail to maintain availability of the assigned Real-Time 10-minute Ramp and Uncertainty Reserve Up for a Real-time Settlement Interval shall be allocated as credits to Market Participants based on their pro rata share of the 10-minute Ramp and Uncertainty Reserve Up Obligation megawatts in the interval in which the charges were incurred, except that Market Participants that incur a charge for failure to maintain availability of these reserves in the given interval and also have an applicable 10-minute Ramp and Uncertainty Reserve Up Obligation shall not be included in the allocation of such credits.

3.2.3A.002 10-minute Ramp and Uncertainty Reserve Down.

(a) Market Participants shall have an obligation for 10-minute Ramp and Uncertainty Reserve Down based on the quantity of 10-minute Ramp and Uncertainty Reserve Down procured for the Reserve Zone. A Market Participant's obligation to pay for 10-minute Ramp and Uncertainty Reserve Down shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus exports for the Real-time Settlement Interval ("10-minute Ramp and Uncertainty Reserve Down Obligation"). A Market Participant with an 10-minute Ramp and Uncertainty Reserve Down Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for 10-minute Ramp and Uncertainty Reserve Down for each Real-time Settlement Interval as defined in sections 3.2.3A.002(b)(i) and (ii) below.

(b) Resources assigned to provide 10-minute Ramp and Uncertainty Reserve Down at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for 10-minute Ramp and Uncertainty Reserve Down provided by generation resources and Economic Load Response Participant resources assigned to provide 10-minute Ramp and Uncertainty Reserve Down by the Office of the Interconnection in the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Market shall be equal to the product of the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price multiplied by the megawatt amount of 10-minute Ramp and Uncertainty Reserve Down such resource is assigned to provide for the hour. When

calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

(ii) Credits for 10-minute Ramp and Uncertainty Reserve Down provided by generation resources and Economic Load Response Participant resources assigned to provide 10-minute Ramp and Uncertainty Reserve Down by the Office of the Interconnection in the Real-time 10-minute Ramp and Uncertainty Reserve Down Market shall be determined for each Real-time Settlement Interval based on the sum on their Real-time Settlement Interval deviations determined in accordance with the following equation:

(A - B) * C

Where:

A = For each Real-time Settlement Interval, the megawatts of 10-minute Ramp and Uncertainty Reserve Down from that resource assigned by the Office of the Interconnection in the Real-time 10-minute Ramp and Uncertainty Reserve Down Market;

B = For each Real-time Settlement Interval, the megawatts of 10-minute Ramp and Uncertainty Reserve Down from that resource assigned by the Office of the Interconnection in the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Market; and

C = For each Real-time Settlement Interval, the Real-time 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price.

(iii) Resources pool-scheduled to provide 10-minute Ramp and Uncertainty Reserve Down shall be credited a reserve uplift credit as determined in accordance with section 3.2.3A.03 below.

(c) 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices

(i) For the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Market, the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price shall be determined for each bus by the Office of the Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time 10-minute Ramp and Uncertainty

Reserve Down market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time 10-minute Ramp and Uncertainty Reserve Down Market, the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price shall be determined for each bus by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.5.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning 10-minute Ramp and Uncertainty Reserve Down, then the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning 10-minute Ramp and Uncertainty Reserve Down, then the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices associated with such Market Suspension shall be the average of the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices for the affected Operating Day, then the Real-time 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices associated with such Market Suspension shall be the Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices for each corresponding hour. If no such Day-ahead 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices exist, then the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices associated with such Market Suspension shall be the average of the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning 10-minute Ramp and Uncertainty Reserve Down. Resources will be compensated for any necessary uplift costs via the reserve uplift credit calculated in

section 3.2.3A.03 below using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

(iii) For purposes of settlements, the 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price shall be floored at $0/MWh.

(d) For each Real-time Settlement Interval, a share of the sum of the reserve uplift credits calculated in accordance with section 3.2.3A.03 below shall be allocated and charged to each Market Participant with a 10-minute Ramp and Uncertainty Reserve Down Obligation for the Real-time Settlement Interval as further described in section 3.2.3A.03(j) below.

(e) A generation resource or Economic Load Response Participant Resource that has been assigned to provide 10-minute Ramp and Uncertainty Reserve Down by the Office of the Interconnection in real-time but fails to maintain availability commensurate with assignment as described in the PJM Manuals will be subject to an unavailability charge. The unavailability charge shall be the amount of Real-Time 10-minute Ramp and Uncertainty Reserve Down capability that was not maintained for each Real-time Settlement Interval at a rate equal to the greater of (i) 1.25 times the Real-time 10-minute Ramp and Uncertainty Reserve Down Locational Clearing Price and (ii) the per megawatt cost for the resource to provide the assigned 10-minute Ramp and Uncertainty Reserve Down (inclusive of real-time make whole costs and the cost of buying out of the resource's 10-minute Ramp and Uncertainty Reserve Down assignment in the Day-ahead Market as further described in the PJM Manuals). In no event shall this rate be less than $0/MWh.

The charges assessed to resources that fail to maintain availability of the assigned Real-Time 10-minute Ramp and Uncertainty Reserve Down for a Real-time Settlement Interval shall be allocated as credits to Market Participants based on their pro rata share of the 10-minute Ramp and Uncertainty Reserve Down Obligation megawatts in the interval in which the charges were incurred, except that Market Participants that incur a charge for failure to maintain availability of these reserves in the given interval and also have an applicable 10-minute Ramp and Uncertainty Reserve Down Obligation shall not be included in the allocation of such credits.

3.2.3A.003 30-minute Ramp and Uncertainty Reserve.

(a) Market Participants shall have an obligation for 30-minute Ramp and Uncertainty Reserve based on the quantity of 30-minute Ramp and Uncertainty Reserve procured for the Reserve Zone. A Market Participant's obligation to pay for 30-minute Ramp and Uncertainty Reserve shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus exports for the Real-time Settlement Interval ("30-minute Ramp and Uncertainty Reserve Obligation"). A Market Participant with a 30-minute Ramp and Uncertainty Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for 30-minute Ramp and Uncertainty Reserve for each Real-time Settlement Interval as defined in sections 3.2.3A.003(b)(i) and (ii) below.

(b) Resources assigned to provide 30-minute Ramp and Uncertainty Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for 30-minute Ramp and Uncertainty Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide 30-minute Ramp and Uncertainty Reserve by the Office of the Interconnection in the Day-ahead 30-minute Ramp and Uncertainty Reserve Market shall be equal to the product of the Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Price multiplied by the megawatt amount of 30-minute Ramp and Uncertainty Reserve such resource is assigned to provide for the hour. When calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

(ii) Credits for 30-minute Ramp and Uncertainty Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide 30-minute Ramp and Uncertainty Reserve by the Office of the Interconnection in the Real-time 30-minute Ramp and Uncertainty Reserve Market shall be determined for each Real-time Settlement Interval based on their Real-time Settlement Interval deviations determined in accordance with the following equation:

(A - B) * C

Where:

A = For each Real-time Settlement Interval, the megawatts of 30-minute Ramp and Uncertainty Reserve from that resource assigned by the Office of the Interconnection in the Real-time 30-minute Ramp and Uncertainty Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of 30-minute Ramp and Uncertainty Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead 30-minute Ramp and Uncertainty Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time 30-minute Ramp and Uncertainty Reserve Locational Clearing Price.

(iii) Resources pool-scheduled to provide 30-minute Ramp and Uncertainty Reserve shall be credited a reserve uplift credit as determined in accordance with section 3.2.3A.03 below.

(c) 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices

(i) For the Day-ahead 30-minute Ramp and Uncertainty Reserve Market, the 30-minute Ramp and Uncertainty Reserve Locational Clearing Price shall be determined

for each bus by the Office of the Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time 30-minute Ramp and Uncertainty Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time 30-minute Ramp and Uncertainty Reserve Market, the 30-minute Ramp and Uncertainty Reserve Locational Clearing Price shall be determined for each bus by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.5.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning 30-minute Ramp and Uncertainty Reserve, then the 30-minute Ramp and Uncertainty Reserve Locational Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning 30-minute Ramp and Uncertainty Reserve, then the 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices for the affected Operating Day, then the Real-time 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices associated with such Market Suspension shall be the Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices for each corresponding hour. If no such Day-ahead 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices exist, then the 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the 30-minute Ramp and Uncertainty Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the 30-minute Ramp and Uncertainty Reserve Locational Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning 30-minute Ramp and Uncertainty Reserve. Resources will be compensated for any necessary uplift costs via the reserve uplift credit calculated in section 3.2.3A.03 below using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

(iii) For purposes of settlements, the 30-minute Ramp and Uncertainty Reserve Locational Clearing Price shall be floored at $0/MWh.

(d) For each Real-time Settlement Interval, a share of the sum of the reserve uplift credits calculated in accordance with section 3.2.3A.03 shall be allocated and charged to each Market Participant with a 30-minute Ramp and Uncertainty Reserve Obligation for the Real-time Settlement Interval as further described in section 3.2.3A.03(j).

(e) A generation resource or Economic Load Response Participant Resource that has been assigned to provide 30-minute Ramp and Uncertainty Reserve by the Office of the Interconnection in real-time but fails to maintain availability commensurate with this assignment as described in the PJM Manuals will be subject to an unavailability charge unless a Synchronized Reserve Event is in effect and the resource has been directed to deploy Synchronized Reserve. The unavailability charge shall be the amount of Real-Time 30-minute Ramp and Uncertainty Reserve capability that was not maintained for each Real-time Settlement Interval at a rate equal to the greater of (i) 1.25 times the Real-time 30-minute Ramp and Uncertainty Reserve Locational Clearing Price and (ii) the per megawatt cost for the resource to provide the assigned 30-minute Ramp and Uncertainty Reserve (inclusive of real-time opportunity costs and the cost of buying out of the resource's 30-minute Ramp and Uncertainty Reserve assignment in the Day-ahead Market as further described in the PJM Manuals). In no event shall this rate be less than $0/MWh.

The charges assessed to resources that fail to maintain availability of the assigned Real-Time 30-minute Ramp and Uncertainty Reserve in a Real-Time Settlement Interval shall be allocated as credits to Market Participants based on their pro rata share of the 30-minute Ramp and Uncertainty Reserve Obligation megawatts in the interval in which the charges were incurred, except that Market Participants that incur a charge for failure to maintain availability of these reserves in the given interval and also have an applicable 30-minute Ramp and Uncertainty Reserve Obligation shall not be included in the allocation of such credits.

3.2.3A.004 60-minute Reserve.

(a) Market Participants shall have an obligation for 60-minute Reserve based on the quantity of 60-minute Reserve procured for the Reserve Zone. A Market Participant's obligation to pay for 60-minute Reserve shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus exports for the Real-time Settlement Interval ("60-minute Reserve Obligation"). A Market

Participant with a 60-minute Reserve Obligation shall be charged the pro rata share of the sum of day-ahead credits for 60-minute Reserve for each Real-time Settlement Interval as defined in section 3.2.3A.004(b) below.

(b) Resources assigned to provide 60-minute Reserve at the direction of the Office of the Interconnection shall be credited the product of the Day-ahead 60-minute Reserve Market Clearing Price multiplied by the megawatt amount of 60-minute Reserve such resource is scheduled to provide for the hour. When calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

(c) The Day-ahead 60-minute Reserve Market Clearing Price shall be determined for the Reserve Zone by the Office of the Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead 60-minute Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead 60-minute Reserve Market Clearing Price of zero dollars per megawatt-hour.

(d) Resources assigned 60-minute Reserve in the Day-ahead Market are expected to come online and supply energy and/or reserves consistent with their Day-ahead 60-minute Reserve Assignment when dispatched by the Office of the Interconnection for energy in real-time.

(e) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide 60-minute Reserve in the Day-ahead Market and is subsequently dispatched by the Office of the Interconnection to supply energy in real-time during the corresponding operating hour, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach the Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a 60-minute Reserve non-performance charge for each Real-time Settlement Interval for the hour in which it was assigned 60-minute Reserve and was deemed as non-compliant with its 60-minute Reserve performance obligations as further described in the PJM Manuals. The 60-minute Reserve non-performance charge for an interval shall be assessed at a rate equal to the greater of: (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that interval, and (ii) 1.5 times the Day-ahead 60-minute Reserve Market Clearing Price, for each unit of 60-minute Reserve shortfall as further described in the PJM Manuals.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide 60-minute Reserve and is

subsequently dispatched to supply the 60-minute Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

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 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a 60-minute Reserve non-performance charge for each real-time interval in which it was assigned 60-minute Reserve and was deemed as non-compliant with its 60-minute Reserve performance obligations as further described in the PJM Manuals. The 60-minute Reserve non-performance charge for an interval shall be assessed at a rate equal to the greater of: (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that interval, and (ii) 1.5 times the Day-ahead 60-minute Reserve Market Clearing Price, for each unit of 60-minute Reserve shortfall as further described in the PJM Manuals.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a 60-minute Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in this section (iii), within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a 60-minute Reserve non-performance charge for each real-time interval in which it was assigned 60-minute Reserve and was deemed as non-compliant with its 60-minute Reserve performance obligations. The 60-minute Reserve non-performance charge for an interval shall be assessed at a rate equal to the greater of: (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that interval, and (ii) 1.5 times the Day-ahead 60-minute Reserve Market Clearing Price, for each unit of 60-minute Reserve shortfall as further described in the PJM Manuals.

(iv) For a generation resource that fails to reach Economic Minimum and for an Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, if the Market Participant updates the status of the resource to reflect its inability to start or reduce load after the issuance of such instruction by the Office of the Interconnection, the above 60-minute Reserve non-performance charge will be applied until it is deemed as unavailable as described in the PJM Manuals, following which the resource will be assessed an unavailability charge as described in 3.2.3A.004(f) below.

If a generation resource or an Economic Load Response Participant Resource has a delayed response, that is, exceeding 30 minutes, it will be assessed the above 60-minute Reserve non-performance charge for the number of Real-time Settlement Intervals between the time it was expected to reach the Economic Minimum output until the time it is deemed to meet its 60-minute Reserve performance obligation as described in the PJM Manuals.

(v) The 60-minute Reserve non-performance charges shall be allocated as credits to Market Participants based on their pro rata share of the 60-minute Reserve Obligation megawatts in the Real-Time Settlement Interval(s) corresponding to the 60-minute Reserve non-performance charges for the Reserve Zone, except that Market Participants that incur a 60-minute Reserve non-performance charge in the given interval and also have an applicable 60-minute Reserve Obligation during such interval shall not be included in the allocation of the corresponding hourly credits.

(f) A generation resource or Economic Load Response Participant Resource that has been assigned to provide 60-minute Reserve megawatts by the Office of the Interconnection in the Day-ahead Market must be generating energy or reducing load or be available to generate energy or reduce load commensurate with its energy and reserve assignments as described in the PJM Manuals; otherwise, it will be charged a 60-minute Reserve unavailability charge for the amount of Day-ahead 60-minute Reserve capability that was not maintained for each Real-time Settlement Interval at a rate equal to the greater of (i) 1.25 times the Day-ahead 60-minute Reserve Market Clearing Price, and (ii) the Real-time Secondary Reserve Locational Clearing Price. In no event shall this rate be less than $0/MWh.

The charges assessed to resources that fail to maintain availability of the assigned Day-ahead 60-minute Reserve shall be allocated as credits to Market Participants based on their pro rata share of the 60-minute Reserve Obligation megawatts in the Real-time Settlement Interval(s) in which the charges were incurred, except that Market Participants that incur a charge for failure to maintain availability of these reserves in the given interval and also have an applicable 60-minute Reserve Obligation shall not be included in the allocation of such credits.

3.2.3A.01 Secondary Reserve.

(a) Market Participants shall have an obligation for Secondary Reserve based on the quantity of Secondary Reserve procured for the Reserve Zone. A Market Participant's obligation to pay for Secondary Reserve shall be based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in the Reserve Zone plus

exports for the Real-time Settlement Interval ("Secondary Reserve Obligation"). A Market Participant with a Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve for each Real-time Settlement Interval as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Locational Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide for the hour. When calculating this credit for a single Real-time Settlement Interval, the foregoing credit shall be divided by 12.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each Real-time Settlement Interval based on their Real-time Settlement Interval deviations determined in accordance with the following equation:

(A - B) * C

Where:

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market.

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Locational Clearing Price.

(iii) Resources pool-scheduled for Secondary Reserve shall be credited a reserve uplift credit as described in section 3.2.3A.03 below.

(c) [Reserved for future use]

(d) Secondary Reserve Locational Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Locational Clearing Price shall be determined for each bus by the Office of the

Interconnection for each hour of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.6.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Locational Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Locational Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Locational Clearing Price shall be determined for each bus by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day in accordance with Operating Agreement, Schedule 1, section 2.5.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Locational Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Locational Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Locational Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Locational Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Locational Clearing Prices exist, then the Secondary Reserve Locational Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Locational Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary

Reserve Locational Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for any necessary uplift costs via the reserve uplift credit calculated in section 3.2.3A.03 below using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

(iii) For purposes of settlements, the Secondary Reserve Locational Clearing Price shall be floored at $0/MWh.

(e) [Reserved for future use]
(f) [Reserved for future use]

(g) For each Real-time Settlement Interval, a share of the sum of the reserve uplift credits calculated in accordance with section 3.2.3A.03 below shall be allocated and charged to each Market Participant with a Secondary Reserve Obligation in the Real-time Settlement Interval as further described in section 3.2.3A.03(j) below.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a Secondary Reserve non-performance charge for each real-time interval in which it was assigned Secondary Reserve and was deemed as non-compliant with its Secondary Reserve performance obligations as further described in the PJM Manuals. The Secondary Reserve non-performance charge will be assessed for each megawatt of Real-time Secondary Reserve performance shortfall at a rate equal to the greater of (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that Real-time Settlement Interval and (ii) the per megawatt cost for the resource to provide the assigned Real-time Secondary Reserve (inclusive of the cost of buying out of the resource's Secondary Reserve assignment in the Day-ahead Market) as further described in the PJM Manuals.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

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 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a Secondary Reserve non-performance charge for each real-time interval in which it was assigned Secondary Reserve and was deemed as non-compliant with its Secondary Reserve performance obligations as further described in the PJM Manuals. The Secondary Reserve non-performance charge for an interval shall be assessed at a rate equal to the greater of (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that interval and (ii) the per megawatt cost for the resource to provide the assigned Real-time Secondary Reserve (inclusive of the cost of buying out of the resource's Secondary Reserve assignment in the Day-ahead Market) for each megawatt of Real-time Secondary Reserve shortfall as further described in the PJM Manuals.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource will be assessed a Secondary Reserve non-performance charge for each real-time interval in which it was assigned Secondary Reserve and was deemed as non-compliant with its Secondary Reserve performance obligations as further described in the PJM Manuals. The Secondary Reserve non-performance charge for an interval shall be assessed at a rate equal to the greater of (i) 1.5 times the Real-time Secondary Reserve Locational Clearing Price for that interval and (ii) the per megawatt cost for the resource to provide the assigned Real-time Secondary Reserve (inclusive of the cost of buying out of the resource's Secondary Reserve assignment in the Day-ahead Market) for each megawatt of Real-time Secondary Reserve shortfall as further described in the PJM Manuals.

(iv) The Secondary Reserve non-performance charges for a Real-time Settlement Interval shall be allocated as credits to Market Participants based on their pro

rata share of the Secondary Reserve Obligation megawatts in the interval corresponding to the Secondary Reserve non-performance charges for the Reserve Zone, except that Market Participants that incur a Secondary Reserve non-performance charge and also have an applicable Secondary Reserve Obligation during such interval shall not be included in the allocation of the corresponding credits.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, 30-minute Reserve, and Day-Ahead Scheduling Reserve, for the Reserve Zone to procure sufficient reserves to meet, as applicable, (a) Synchronized Reserve Requirement; (b) 10-minute Ramp and Uncertainty Reserve Up Requirement; (c) 10-minute Ramp and Uncertainty Reserve Down Requirement; (d) 30-minute Ramp and Uncertainty Reserve Requirement; (e) 30-minute Reserve Requirement; and (f) Day-Ahead Scheduling Reserve Requirement. The Operating Reserve Demand Curves established for each reserve service type, except Day-Ahead Scheduling Reserve, shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curve established for the Day-Ahead Scheduling Reserve shall be used to commit such reserves in the day-ahead reserve market. The Operating Reserve Demand Curves shall be determined in accordance with the PJM Manuals and the following. In instances where the Operating Reserve Demand Curve is a continuous, sloping curve, the curve shall be discretized into segments for purposes of implementation in the market clearing engines. The Office of the Interconnection shall update the uncertainty values dictating the shape of the Operating Reserve Demand Curve and reserve requirement for the applicable reserve services as described in the PJM Manuals.

(a) The Operating Reserve Demand Curve for the Synchronized Reserve service is a set of ordered pairs $\{(r, p(r)) : r \geq 0, p(r) \geq 0\}$ where r is the quantity of Synchronized Reserve in MW and $p(r)$ is the marginal value in $/MWh at the Synchronized Reserve level r. For any Synchronized Reserve level r between 0 MW and the Synchronized Reserve Requirement inclusive of the endpoints, $p(r)$ shall be set at a constant $2,100/MWh. For any Synchronized Reserve level r exceeding the Synchronized Reserve Requirement, $p(r)$ shall be $0/MWh.

(b) The Operating Reserve Demand Curve for the 10-minute Ramp and Uncertainty Reserve Up service is a set of ordered pairs $\{(r, p(r)) : r \geq 0, p(r) \geq 0\}$ where r is the quantity of 10-minute Ramp and Uncertainty Reserve Up in MW and the monotone non-increasing map $p(r)$ is the marginal value in $/MWh at the 10-minute Ramp and Uncertainty Reserve Up level r. The Operating Reserve Demand Curve for the 10-minute Ramp and Uncertainty Reserve Up service has the following features:

(i) For any 10-minute Ramp and Uncertainty Reserve Up level r between 0 MW and $\max\{\overline{r} - \tilde{r}, 0\}$, the marginal value $p(r)$ is set at the maximum price of $1,900/MWh. Here, $\overline{r}$ is the adjusted forecast net-load ramp, defined as the difference in the adjusted forecast net-load 10 minutes beyond the current

energy dispatch interval minus the adjusted forecast net-load for the current energy dispatch interval; $\tilde{r}$ is the corresponding net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts; and the adjusted forecast net-load = load forecast - wind forecast - solar forecast - expected energy from resources starting-up.

(ii) The marginal value $p(\overline{r}_+)$, where $\overline{r}_+ = \max(\overline{r}, 0)$ and $\overline{r}$ is the adjusted forecast net-load ramp, is set at $1,000/MWh.

(iii) The marginal value at the 10-minute Ramp and Uncertainty Reserve Up Requirement is set at $100/MWh.

(iv) For $\{r \geq 0: p(r) \in (\$100/\text{MWh}, \$1{,}900/\text{MWh})\}$, the marginal value is given by,

$$p(r) = \big(1 - F(r)\big) \times \$2{,}000/\text{MWh},$$

where $F(r)$ is the cumulative distribution function computed based on the uncertainty associated with the 10-minute forward net-load ramp as further described in the PJM Manuals.

(v) For any 10-minute Ramp and Uncertainty Reserve Up level r exceeding the 10-minute Ramp and Uncertainty Reserve Up Requirement, $p(r)$ shall be $0/MWh.

(c) The Operating Reserve Demand Curve for the 10-minute Ramp and Uncertainty Reserve Down service is a set of ordered pairs $\{(r, p(r)): r \geq 0, p(r) \geq 0\}$ where r is the quantity of 10-minute Ramp and Uncertainty Reserve Down in MW and the monotone non-increasing map $p(r)$ is the marginal value in $/MWh at the 10-minute Ramp and Uncertainty Reserve Down level r. The Operating Reserve Demand Curve for the 10-minute Ramp and Uncertainty Reserve Down service has the following features:

(i) For any 10-minute Ramp and Uncertainty Reserve Down level r between 0 MW and $\max\{-\overline{r} - \tilde{r}, 0\}$, the marginal value $p(r)$ is set at the maximum price of $190/MWh. Here, $\overline{r}$ is the forecast net-load ramp, defined as the difference in the forecast net-load 10 minutes beyond the current energy dispatch interval minus the forecast net-load for the current energy dispatch interval; $\tilde{r}$ is the corresponding net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts; and the forecast net-load = load forecast - wind forecast - solar forecast.

(ii) The marginal value $p(\ (-\overline{r})_+)$, where $(-\overline{r})_+ = \max(-\overline{r}, 0)$ and $\overline{r}$ is the forecast net-load ramp, is set at $100/MWh.

(iii) The marginal value at the 10-minute Ramp and Uncertainty Reserve Down Requirement is set at $10/MWh.

(iv) For $\{r \geq 0: p(r) \in (\$10/\text{MWh}, \$190/\text{MWh})\}$, the marginal value is given by,

$$p(r) = F(-r) \times \$200/\text{MWh},$$

where $F(r)$ is the cumulative distribution function computed based on the uncertainty associated with the 10-minute forward net-load ramp as described in 3.2.3A.02(b) above and further described in the PJM Manuals.

(v) For any 10-minute Ramp and Uncertainty Reserve Down level r exceeding the 10-minute Ramp and Uncertainty Reserve Down Requirement, $p(r)$ shall be \$0/MWh.

(d) The Operating Reserve Demand Curve for the 30-minute Ramp and Uncertainty Reserve service is a set of ordered pairs $\{(r, p(r)): r \geq 0, p(r) \geq 0\}$ where r is the quantity of 30-minute Ramp and Uncertainty Reserve in MW and the monotone non-increasing map $p(r)$ is the marginal value in \$/MWh at the 30-minute Ramp and Uncertainty Reserve level r. The Operating Reserve Demand Curve for the 30-minute Ramp and Uncertainty Reserve service has the following features:

(i) For any 30-minute Ramp and Uncertainty Reserve level r between 0 MW and $\max\{\overline{r} - \tilde{r}, 0\}$, the marginal value $p(r)$ is set at the maximum price of \$1,900/MWh. Here, $\overline{r}$ is the adjusted forecast net-load ramp, defined as the difference in the adjusted forecast net-load 30 minutes beyond the current energy dispatch interval minus the adjusted forecast net-load 10 minutes beyond the current energy dispatch interval; $\tilde{r}$ is the corresponding net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts; and the adjusted forecast net-load = load forecast - wind forecast - solar forecast - expected energy from resources starting-up.

(ii) The marginal value $p(\overline{r}_+)$, where $\overline{r}_+ = \max(\overline{r}, 0)$ and $\overline{r}$ is the adjusted forecast net-load ramp, is set at \$1,000/MWh.

(iii) The marginal value at the 30-minute Ramp and Uncertainty Reserve Requirement is set at \$100/MWh.

(iv) For $\{r \geq 0: p(r) \in (\$100/\text{MWh}, \$1{,}900/\text{MWh})\}$, the marginal value is given by,

$$p(r) = \big(1 - F(r)\big) \times \$2{,}000/\text{MWh},$$

where $F(r)$ is the cumulative distribution function computed based on the uncertainty associated with the 30-minute forward net-load ramp beyond the 10-minute forward net-load ramp as further described in the PJM Manuals.

(v) For any 30-minute Ramp and Uncertainty Reserve level r exceeding the 30-minute Ramp and Uncertainty Reserve Requirement, $p(r)$ shall be \$0/MWh.

(e) The Operating Reserve Demand Curve for the 30-minute Reserve service is a set of ordered pairs $\{(r, p(r)): r \geq 0, p(r) \geq 0\}$ where r is the quantity of 30-minute

Reserve in MW and the monotone non-increasing map $p(r)$ is the marginal value in \$/MWh at the 30-minute Reserve level r. The Operating Reserve Demand Curve for the 30-minute Reserve service has the following features:

(i) For any 30-minute Reserve level r between 0 MW and $\max\{\text{MSSC} + \overline{r} - \tilde{r}, \text{MSSC}\}$, the marginal value $p(r)$ is set at the maximum price of \$190/MWh. Here, MSSC is the largest contingency in the Reserve Zone, $\overline{r}$ is the adjusted forecast net-load ramp, defined as the difference in the adjusted forecast net-load 30 minutes beyond the current energy dispatch interval minus the adjusted forecast net-load 10 minutes beyond the current energy dispatch interval; $\tilde{r}$ is the corresponding net-load uncertainty, including uncertainty associated with the wind, solar and load forecasts; and the adjusted forecast net-load = load forecast - wind forecast - solar forecast - expected energy from resources starting-up.

(ii) When $\overline{r} > 0$, the marginal value $p(\text{MSSC} + \overline{r})$ is set at \$100/MWh.

(iii) When the 30-minute Reserve Requirement is strictly greater than the largest contingency in the Reserve Zone, the marginal value at the 30-minute Reserve Requirement is set at \$10/MWh.

(iv) For $\{r \geq \text{MSSC}: p(r) \in (\$10/\text{MWh}, \$190/\text{MWh})\}$, the marginal value is given by,

$$p(r) = \big(1 - F(r - \text{MSSC})\big) \times \$200/\text{MWh},$$

where $F(r)$ is the cumulative distribution function computed based on the uncertainty associated with the 30-minute forward net-load ramp beyond the 10-minute forward net-load ramp as further described in the PJM Manuals.

(v) For any 30-minute Reserve level r exceeding the 30-minute Reserve Requirement, $p(r)$ shall be \$0/MWh.

(f) The Operating Reserve Demand Curve for the Day-Ahead Scheduling Reserve service is a set of ordered pairs $\{(r, p(r)): r \geq 0, p(r) \geq 0\}$ where r is the quantity of Day-Ahead Scheduling Reserve in MW and $p(r)$ is the marginal value in \$/MWh at the Day-Ahead Scheduling Reserve level r. For any Day-Ahead Scheduling Reserve level r between 0 MW and the Day-Ahead Scheduling Reserve Requirement inclusive of the endpoints, $p(r)$ shall be set at a constant \$50/MWh. For any Day-Ahead Scheduling Reserve level r exceeding the Day-Ahead Scheduling Reserve Requirement, $p(r)$ shall be \$0/MWh.

3.2.3A.03 Reserve Market Uplift

(a) Market Participants with resources that receive pool-scheduled assignments for Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve and/or Secondary Reserve in the day-ahead and/or real-time markets shall be eligible to receive a reserve market

uplift credit. A reserve market uplift credit shall be paid when the reserve revenues do not meet or exceed the costs of providing those reserves.

The reserve market uplift credit for a resource for each Real-time Settlement Interval is calculated in accordance with the following equation, where the resulting credit shall not be less than $0:

Reserve Market Uplift Credit = Total Reserve Costs – Total Reserve Revenues

Where:

Total Reserve Costs = Total RT Reserve Market Offer + Condensing Cost + Min (Real-time Opportunity Cost – Additional DA Buy Out Cost,0) each as defined in sub-section (b) through (e) below.

Total Reserve Revenues = (Total Day-Ahead Reserve Market Clearing Price Credits + Total Balancing Reserve Market Clearing Price Credits + Market Revenue Neutrality Offset - Company Responsible Negative Reserve Revenues), each as defined in sub-sections (f) through (i) below.

(b) Total RT Reserve Market Offer

The total RT reserve market offer shall be the sum of the offers for the real-time assignments across the Synchronized Reserve and Secondary Reserve markets, where the offer for each individual market is calculated as the RT reserve market offer price submitted by the Market Participant times the Real-Time Reserve Market MW assignment for the Real-time Settlement Interval.

(c) Condensing Cost

The condensing cost is calculated for each resource that receives a pool-scheduled real-time reserve assignment as a synchronous condenser. The resource's condensing cost shall be determined as follows: [real-time Condense Energy Use multiplied by the Real-time Locational Marginal Price at the generation bus of the generation resource] plus [real-time Condense Startup Cost allocated to the Real-time Settlement Interval as described in PJM Manuals].

(d) Real-time Opportunity Cost

Real-time Opportunity Cost represents the energy profit a resource forgoes when it is backed down from its economic energy set point to make room for a pool-scheduled, real-time reserve assignment, or any loss associated with moving its output above its economic energy set point in order to accommodate a pool-scheduled, real-time 10-minute Ramp and Uncertainty Reserve Down assignment.

(i) For all generation resources moved up or down off of their economic energy set point in order to provide real-time reserves, except for those generation resources that are

self-scheduled to provide Synchronized Reserve, operating as a synchronous condenser or hydroelectric generation resources, the unit-specific opportunity cost (in dollars) considered in the reserve market uplift calculation for a Real-time Settlement Interval shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the resource, (ii) the resource's Final Offer in the real-time energy market, (iii) the resource's tracking ramp rate-limited expected energy output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the resource's tracking ramp rate-limited expected energy output level to accommodate all real-time reserve MW assignments across all reserve markets in that Real-time Settlement Interval.

(ii) For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at the generation bus for the resource multiplied by the total pool-scheduled real-time reserve market assignment across the Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve and Secondary Reserve markets.

The unit-specific opportunity costs for each pool-scheduled hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the real-time Locational Marginal Price at the generation bus for the resource minus the average real-time Locational Marginal Price at the generation bus for the resource 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 multiplied by the total pool-scheduled real-time reserve market assignment across the Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 30-minute Ramp and Uncertainty Reserve and Secondary Reserve markets.

The unit-specific opportunity costs for each pool-scheduled hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) Notwithstanding the foregoing, opportunity costs for Economic Load Response Participant resources, any resource self-scheduled for Synchronized Reserves in real-time, resources assigned real-time reserves in condensing mode, or any resource assigned real-time reserves in an offline state are zero for purposes of calculating reserve uplift.

(e) Additional DA Buy Out Cost

When calculating the costs considered in the reserve market uplift calculation, the real-time opportunity cost represented in subsection (d) above is further adjusted to recognize instances where if the resource was not given a reserve assignment in a given real-time reserve market, and was instead assigned for energy in real-time, that resource would have to incur an additional cost to buy out of its day-ahead reserve position in the given market and therefore, the resource would

not be able to capture the full opportunity cost in (d) above. The Additional DA Buy Out Cost considered in the reserve market uplift calculation for a given Real-time Settlement Interval represents this adjustment and shall be the sum of the Additional DA Buy Out Costs for the Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve and Secondary Reserve markets, where the Additional DA Buy Out Cost for a given market for a given Real-time Settlement Interval is as follows:

Additional DA Buy Out Cost for a given market = A * Min (B, C, D)

Where:

A = the real-time locational reserve market clearing price for the resource for the given market minus the day-ahead locational reserve market clearing price for the resource for the given market.

B = the resource's day-ahead reserve assignment for the given market.

C = the resource's real-time reserve assignment for the given market.

D = the portion of the megawatts the resource was backed down from its economic set point in order to provide the real-time reserve assignment which overlaps with the day-ahead reserve assignment for that market, as further described in the PJM Manuals.

(f) Total Day-Ahead Reserve Market Clearing Price Credits

When calculating the credits considered in the reserve market uplift calculation for a resource, Total Day-Ahead Reserve Market Clearing Price Credits are the sum of the following for the Real-time Settlement Interval:

(i) The day-ahead Synchronized Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A(b)(i).

(ii) The day-ahead 10-minute Ramp and Uncertainty Reserve Up locational clearing price credits for the resource as calculated in subsection 3.2.3A.001(b)(i).

(iii) The day-ahead 10-minute Ramp and Uncertainty Reserve Down locational clearing price credits for the resource as calculated in subsection 3.2.3A.002(b)(i).

(iv) The day-ahead 30-minute Ramp and Uncertainty Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A.003(b)(i).

(v) The day-ahead Secondary Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A.01(b)(i).

(g) Total Balancing Reserve Market Clearing Price Credits

When calculating the credits considered in the reserve market uplift calculation for a resource, Total Balancing Reserve Market Clearing Price Credits are the sum of the following for the Real-time Settlement Interval:

(i) The balancing Synchronized Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A(b)(ii).

(ii) The balancing 10-minute Ramp and Uncertainty Reserve Up locational clearing price credits for the resource as calculated in subsection 3.2.3A.001(b)(ii).

(iii) The balancing 10-minute Ramp and Uncertainty Reserve Down locational clearing price credits for the resource as calculated in subsection 3.2.3A.002(b)(ii).

(iv) The balancing 30-minute Ramp and Uncertainty Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A.003(b)(ii).

(v) The balancing Secondary Reserve locational clearing price credits for the resource as calculated in subsection 3.2.3A.01(b)(ii).

(h) Market Revenue Neutrality Offset

The Market Revenue Neutrality Offset is included in the reserve market uplift calculation in recognition of the fact that the additional energy profit a resource receives from shifting energy and reserve assignments between the day-ahead and real-time markets can fully or partially offset any negative revenue associated with buying out of a day-ahead reserve assignment when the resource's reserve assignment is reduced in real-time, thereby reducing the uplift the resource requires.

For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each generation resource with a change in real-time energy market megawatt output from a day-ahead energy market megawatt assignment due to the net decrease in the total real-time reserve assignments across the Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, and Secondary Reserve products from the total day-ahead reserve market megawatt assignment across those same reserve products, if eligible.

A resource is not eligible for Market Revenue Neutrality Offset in a Real-time Settlement Interval for any of the following conditions as further described in the PJM ThManuals:

(A) A resource's total real-time assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide in real-time a reserve product it was assigned to provide in the day-ahead market;

(C) A resource's Final Offer is less than its Committed Offer and there was a reduction in the MW assignment for the reserve markets that require an increase in energy when deployed or the Final Offer is greater than its Committed Offer and there was a reduction in the MW assignment for the reserve markets that require a decrease in energy when deployed;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its reserve offer price in the real-time Synchronized Reserve or Secondary Reserve markets from its offer price in the respective day-ahead reserve market.

(i) Company Responsible Negative Reserve Revenues

Company Responsible Negative Reserve Revenues is the portion of the reserve uplift credit stemming from buying out of the day-ahead reserve market position, as detailed in the PJM Manuals, that a Market Participant is not eligible to receive because the Market Participant's actions resulted in the reduction in the resource's real-time reserve assignment from the day-ahead reserve assignment. For each Real-time Settlement Interval, Company Responsible Negative Reserve Revenues is calculated for each resource (i) with a net decrease in the total real-time reserve assignments across the Synchronized Reserve, 10-minute Ramp and Uncertainty Reserve Up, 10-minute Ramp and Uncertainty Reserve Down, 30-minute Ramp and Uncertainty Reserve, and Secondary Reserve products from the total day-ahead reserve market megawatt assignment across those same reserve products and (ii) that is not eligible for the Market Revenue Neutrality Offset as described in subsection (h) above.

(j) For each Real-time Settlement Interval, the reserve uplift credits calculated in this section shall be allocated and charged to Market Participants based on their pro rata share of the sum of the following in that Real-time Settlement Interval: real-time purchases of Synchronized Reserve as described in section 3.2.3A(h), 10-minute Ramp and Uncertainty Reserve Up Obligation as described in section 3.2.3A.001(f), 10-minute Ramp and Uncertainty Reserve Down Obligation as described in 3.2.3A.002(d), 30-minute Ramp and Uncertainty Reserve Obligation as described in 3.2.3A.003(d), and Secondary Reserve Obligation as described in section 3.2.3A.01(g).

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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where 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 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 for each Real-time Settlement Interval 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 Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to reduce charging to provide Reactive Services is not eligible for compensation under section (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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, 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 (positive generation 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). At the end of each Operating Day, when an Energy Storage Resource Model Participant or a Hybrid Resource is instructed to increase charging 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 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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP revenues at the unit's bus are 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 in an amount equal to {(AG – TRLD MWh) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Operating Agreement, Schedule 1, section 3.2.3(e-1);

UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 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 or if an Energy Storage Resource Model Participant or a Hybrid Resource believes the above calculations in this section 3.2.3B do not accurately compensate the Market Participant for opportunity costs associated with following the Office of the Interconnection's dispatch instructions to modify a unit's charging or discharging 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 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 opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate 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 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 Synchronized Reserve Locational Clearing Price for each Real-time Settlement Interval 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 product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) 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 in accordance with section 3.2.3(e-2). 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 applicable Synchronized Reserve Requirement. 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 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 Real-time Synchronized Reserve Locational Clearing Price for each applicable interval 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 product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) 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 Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

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 maximum price on the Operating Reserve Demand Curve for the Synchronized Reserve service, 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 applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections 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 applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections 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 energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval 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 withdrawals and injections 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 Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

5.6 Transmission Constraint Penalty Factors

5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. If a Market Suspension greater than twenty-four (24) consecutive hours is declared in the Real-time Energy Market as per Operating Agreement, Schedule 1, section 2.5.2, Transmission Constraint Penalty Factors shall not be used to determine the Marginal Value of a transmission constraint. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

5.6.2 Default Transmission Constraint Penalty Factor Values

Transmission constraints modeling the flow of energy located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market when determining the day-ahead security constrained economic dispatch, known as the dispatch run, and $2,000/MWh in the determination of Day-ahead Prices in the pricing

run. Constraints modeling the flow of energy located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of $1,000/MWh or a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

Transmission constraints modeling the joint flow of energy and reserves, as described in the PJM Manuals, located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, will use a default Transmission Constraint Penalty Factor of $1,000/MWh in both the dispatch run and the pricing run of the Day-ahead Energy Market and the Real-time Energy Market. Reserve deliverability constraints will not be modeled on market-to-market coordinated flowgates.

5.6.3 Modifications to Transmission Constraint Penalty Factor Values

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints modeling the flow of energy to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor for transmission constraints modeling the flow of energy when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor for transmission constraints modeling the flow of energy when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint or when congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor but resources are not available for congestion relief between the marginal value of the appreciable resource and the default Transmission Constraint Penalty Factor if the congestion results from a transmission outage needed to address Regional Transmission Expansion Plan criteria or interconnection requests in the impacted area designed to improve system reliability. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value for transmission constraints modeling the flow of energy may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price + Loss Price + Congestion Price (all binding constraints) – Incremental Energy Offer*}}{D_{fax}}$$

Where D_{fax} equals the distribution factor of the resource for the transmission constraint

*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

In the instance where the Transmission Constraint Penalty Factor for the transmission constraint modeling the flow of energy is modified, the values of the Transmission Constraint Penalty Factors for the corresponding transmission constraints modeling the joint flow of energy and reserves, as described in the PJM Manuals, located within the metered boundaries of the PJM Region, will be set to the lesser of (i) half of the revised value of the Transmission Constraint Penalty Factor for the transmission constraint modeling the flow of energy and (ii) $1,000/MWh.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.