WRIGHT &
TALISMAN PC

1200 G Street, N.W.
Suite 600
Washington, D.C. 20005-3802
202.393.1200
Fax 202.393.1240
www.wrightlaw.com

December 27, 2010

Via Electronic Filing
Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER11-2527-000
Ministerial Filing to Reflect Tariff and Operating Agreement Language Accepted in Docket No. ER10-1196-000 in Electronic Tariff

Dear Ms. Bose:

I. Background and Description of Filing

On May 5, 2010, in Docket No. ER10-1196-000, PJM Interconnection, L.L.C. ("PJM"), on behalf of itself and a to be formed entity, PJM Settlement, Inc. ("PJMSettlement"), submitted for filing pursuant to section 205 of the Federal Power Act ("FPA"),[1] for effectiveness on January 1, 2011, revisions to the PJM Open Access Transmission Tariff ("Tariff") and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") clarifying the counterparty to transactions in the PJM markets ("May 5 Filing"). On September 3, 2010, the Commission issued an order conditionally accepting the tariff revisions, to become effective January 1, 2011, subject to PJM making a compliance filing.[2]

Since the May 5 Filing, PJM submitted its baseline electronic tariff filing to comply with Order No. 714[3] on September 17, 2010, in Docket No. ER10-2710.[4] In

1 16 U.S.C. § 824d.

2 *PJM Interconnection, L.L.C.*, 132 FERC ¶ 61,207 (2010) ("September 3 Order").

3 *Electronic Tariff Filings,* Order No. 714, III FERC Stats. & Regs., Regs. Preambles ¶ 31,276 (2008), *as amended* October 23, 2009 ("Order No. 714").

4 PJM's baseline electronic tariff for the Tariff and Operating Agreement is currently pending before the Commission.

Order No. 714, the Commission directed that utilities with tariff revisions that are pending at the time the utility filed its baseline electronic tariff should not file the pending or suspended tariff sections as part of the baseline tariff filing. Rather, utilities were directed to re-file the pending tariff provisions as a compliance filing through the eTariff portal, in electronic tariff filing format, for inclusion in the database after the pending revisions have been accepted by the Commission.[5]

Because the tariff revisions accepted by the September 3 Order were not effective on September 17, 2010, the revisions were not included in PJM's September 17, 2010 baseline filing of the then-effective PJM Tariff and Operating Agreement. Therefore, PJM is required to submit a separate ministerial compliance filing to incorporate the Tariff and Operating Agreement revisions accepted by the September 3 Order into the electronic version of the PJM Tariff and Operating Agreement.

On November 1, 2010, in Docket No. ER11-1987-000, PJM submitted a ministerial filing to incorporate into its electronic tariff a portion of the revisions submitted in the May 5 Filing and accepted by the September 3 Order ("November Ministerial Filing"). The November Ministerial Filing included sections of the revisions accepted by the September 3 Order that involved sections of the PJM Tariff and Operating Agreement that were being further revised in another filing also submitted on November 1, 2010, in Docket No. ER11-1988. Specifically, the November Ministerial Filing included the previously accepted revisions to the PJM Tariff section 6A; Schedule 9; Attachment K-Appendix sections 5.4 and 7.2; and Attachment Q; and Operating Agreement sections 3.3 and 15.2; and Schedule 1 sections 5.4, 5.5, and 7.2.

PJM also explained in the November Ministerial Filing that prior to January 1, 2011, it would submit an additional separate ministerial compliance filing to incorporate the rest of the PJM Tariff and Operating Agreement revisions accepted by the September 3 Order into the electronic version of the PJM Tariff and Operating Agreement.

Accordingly, PJM submits this ministerial filing to incorporate into its electronic tariff the PJM Tariff and Operating revisions submitted in the May 5 Filing and accepted by the September 3 Order, effective January 1, 2011, that were not included in the November Ministerial Filing.[6] This ministerial filing makes no substantive modifications

---

5 Order No. 714 at P 96.

6 The revisions to the tables of contents of the PJM Tariff and the Operating Agreement that were included in the May 5 Filing are not included in this filing to incorporate the changes into the electronic tariff. Because of intervening filings and other revisions to the tables of contents, those revisions will be filed at a later date in connection with more comprehensive revisions to the tables of contents.

to the PJM Tariff or Operating Agreement that have not already been accepted by the Commission in the September 3 Order.[7]

II. Effective Date

PJM requests that the ministerial revisions included in this filing be made effective January 1, 2011, consistent with the effective date granted by the September 3 Order.

III. Documents Enclosed

This filing consists of:

(i) This transmittal letter;

(ii) Portions of the PJM Tariff incorporating previously accepted tariff revisions into the electronic version of the PJM Tariff (in non-redlined format and redlined format in electronic tariff filing format as required by Order No. 714); and

(iii) Portions of the Operating Agreement incorporating previously accepted tariff revisions into the electronic version of the Operating Agreement (in non-redlined format and redlined format in electronic tariff filing format as required by Order No. 714).

---

[7] The portions of the PJM Tariff and Operating Agreement included in this filing reflect in italics pending tariff language submitted in three other dockets (Docket Nos. ER11-2074-000, ER11-2310-000, and ER11-2391-000) with a requested effective date prior to January 1, 2011. The pending tariff revisions are reflected in italics in the following sections: sections 1.10, 3.2 and 3.3A of the Appendix to Attachment K of the PJM Tariff and the corresponding sections of Schedule 1 of the Operating Agreement, and section 6 of Attachment DD of the PJM Tariff.

IV. Communications

Correspondence and communications with respect to this filing should be sent to the following:

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-7756 (phone)
(202) 393-7741 (fax)
glazec@pjm.com

Vincent P. Duane
Vice President & General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403
(610) 666-4367 (phone)
(610) 666-4281 (fax)
duanev@pjm.com

Barry S. Spector
Deborah C. Brentani
Wright & Talisman, P.C.
1200 G Street, N.W.
Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
spector@wrightlaw.com
brentani@wrightlaw.com

V. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[8] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[9] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for Docket No. ER10-1196. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

---

8 *See* 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

9 PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

VI. Conclusion

For the foregoing reasons, PJM respectfully requests that the Commission accept for filing the proposed revisions to the PJM Tariff and Operating Agreement, previously accepted by the Commission, with an effective date of January 1, 2011.

Respectfully submitted,

/s/ *Deborah C. Brentani*

Barry S. Spector
Deborah C. Brentani
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
spector@wrightlaw.com
brentani@wrightlaw.com

Craig Glazer
Vice President – Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W.; Suite 600
Washington, D.C. 20005
(202) 393-7756 (phone)
(202) 393-7741 (fax)
glazec@pjm.com

Vincent P. Duane
Vice President & General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403
(610) 666-4367 (phone)
(610) 666-4281 (fax)
duanev@pjm.com

Attorneys for
PJM Interconnection, L.L.C.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Commission Secretary in Docket No. ER10-1196-000.

Dated at Washington, D.C., this 27th day of December, 2010.

/s/ *Deborah C. Brentani*
Deborah C. Brentani

WRIGHT & TALISMAN, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200

PJM Tariff Revisions

(Redlined Version)

Definitions – C-D

1.3BB.03 Cancellation Costs:

The Costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Part IV and/or Part VI of the Tariff.

1.3C Capacity Interconnection Rights:

The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

1.3D Capacity Resource:

Shall have the meaning provided in the Reliability Assurance Agreement.

1.3E Capacity Transmission Injection Rights:

The rights to schedule energy and capacity deliveries at a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

1.3F Commencement Date:

The date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

1.4 Commission:

The Federal Energy Regulatory Commission.

1.5 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.5.01 Confidential Information:

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

1.5A Consolidated Transmission Owners Agreement:

The 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.

1.5B Constructing Entity:

Either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

1.5C Construction Party:

A party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

1.5D Construction Service Agreement:

Either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

1.6 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.6A Control Zone:

Shall have the meaning given in the Operating Agreement.

1.6B Controllable A.C. Merchant Transmission Facilities:

Transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Part IV and Part VI of the Tariff.

1.6C Costs:

As used in Part IV, Part VI and related attachments to the Tariff, costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

1.6D Counterparty:

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 customer.

1.7 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.7A Customer Facility:

Generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Subparts A of Part IV of the Tariff.

1.7A.01 Customer-Funded Upgrade:

Any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Section 217 of the Tariff, or (ii) is voluntarily undertaken by a market participant in fulfilment of an Upgrade Request pursuant to Section 7.8 of Schedule 1 of the Operating Agreement. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

1.7A.02 Customer Interconnection Facilities:

All facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate 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.

1.7B Daily Capacity Deficiency Rate

Daily Capacity Deficiency Rate is as defined in Schedule 11 of the Reliability Assurance Agreement.

1.7C Deactivation:

The retirement or mothballing of a generating unit governed by Part V of this Tariff.

1.7D Deactivation Avoidable Cost Credit:

The credit paid to Generation Owners pursuant to section 114 of this Tariff.

1.7E Deactivation Avoidable Cost Rate:

The formula rate established pursuant to section 115 of this Tariff.

1.7F Deactivation Date:

The date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

1.7G Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

1.8 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Definitions – O – P - Q

1.27C Office of the Interconnection:

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.~~The Office of the Interconnection, as supervised by the Board of Managers of the PJM Interconnection, L.L.C, acting pursuant to the Operating Agreement.~~

1.28 Open Access Same-Time Information System (OASIS):

The 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.

1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.28A.01 Option to Build:

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

1.28B Optional Interconnection Study:

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

1.28C Optional Interconnection Study Agreement:

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

1.29 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31A Part IV:

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31B Part V:

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31C Part VI:

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties:

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

1.32.01 PJM:

PJM Interconnection, L.L.C.

1.32A PJM Administrative Service:

The services provided by PJM pursuant to Schedule 9 of this Tariff.

1.32B PJM Control Area:

The Control Area that is recognized by NERC as the PJM Control Area.

1.32C PJM Interchange Energy Market:

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

1.32D PJM Manuals:

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

1.32E PJM Region:

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

1.32F PJM South Region:

The VACAR Control Zone.

1.32.F.01 PJMSettlement:

PJM Settlement, Inc. (or its successor).

1.32G PJM West Region:

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; and the Duquesne Light Company.

1.33 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.33A Point of Interconnection:

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

1.34 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.36.01 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.36A Pre-Expansion PJM Zones:

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

1.36A.01 Project Financing:

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

1.36A.02 Project Finance Entity:

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

1.36B Queue Position:

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

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 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 pariticants 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 Schedules 3, 4, 5 and 6) 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. Sections 3.1 through 3.6 below list the six Ancillary Services.

3D [Reserved] ~~Transitional Market Expansion Charge~~

~~The Transmission Provider shall recover certain charges related to the benefits of the expansion of PJM to include the PJM West Region from Generation Providers and customers using Point-to-Point and Network Integration Transmission Service under Schedule 11, "Transitional Market Expansion Charge," which is attached to and made part of this Tariff.~~

7 Billing and Payment

PJMSettlement shall issue bills and billing statements pursuant to the provisions in this section 7 in its own name and as agent for Transmission Provider, as applicable. Payment of bills pursuant to this section 7 shall be made for the benefit of PJMSettlement and Trasnmission Provider, as applicable.

7.1 Billing Procedure:

(a) Monthly Bills.

By the fifth business day of each month, PJMSettlement, in its own name and as agent for Transmission Provider, as applicable, ~~the Transmission Provider~~ shall issue a bill to Transmission Customers and other entities for monthly activity and detailing the charges and credits for all services furnished under the Tariff during the preceding month ("billing month"), excluding amounts billed pursuant to weekly bills for activity during the preceding month.

(b) Weekly Bills.

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

(c) Billing Statement.

PJMSettlement, in its own name and as agent for Transmission Provider, as applicable, ~~Transmission Provider~~ shall provide Transmission Customers and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Transmission Customer's or other entity's activity during the billing month and amounts due, net of activity previously billed.

7.1A Payments:

(a) Monthly Bills.

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

(b) Weekly Bills.

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

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 7.1(b) when due, the Transmission Provider may allow a municipal electric system to make arrangement with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

(a) the Transmission Provider determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;

(b) the municipal electric system reimburses PJM for the actual cost of such working capital;

(c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;

(d) ~~the Transmission Provider~~PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 7,1(b) above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 7.1A(a).;

(e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

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

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

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

(c) Form of Payments.

All payments tendered in satisfaction of a Transmission Customer's or other entity's obligations to PJMSettlement or Transmission Provider shall be in the form of immediately available funds payable to ~~the Transmission Provider~~PJMSettlement, or by wire transfer to a bank named by ~~the Transmission Provider~~PJMSettlement.

(d) Payments by ~~Transmission Provider~~PJMSettlement.

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

(e) Payment Calendar.

A comprehensive billing and settlement calendar will be posted on Transmission Provider's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

7.2 Interest on Unpaid Balances:

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by ~~the Transmission Provider~~PJMSettlement.

7.3 Customer Default:

In the event the Transmission Customer or other entity (a) fails, for any reason, to make payment to PJMSettlement, for the benefit of PJMSettlement or the Transmission Provider, on or before the due date as described above, or (b) fails at any time to meet the Transmission Provider's creditworthiness requirements, and such failure is not corrected within two business days after the Transmission Provider notifies the Transmission Customer or other entity to cure such failure, a default by the Transmission Customer or other entity shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request; provided however, that (i) in the event that a state required retail access program provides for continuation of retail service to affected end-use customers by another supplier that is a Transmission Customer, then the Transmission Provider may, upon default by a Transmission Customer, immediately terminate Transmission Service to the defaulting Transmission Customer for the load of such end-use customers, and (ii) in the event that a Transmission Customer is taking service under Part II to serve load outside of the PJM Region, then the Transmission Provider may, upon default by a Transmission Customer, immediately terminate Transmission Service to the defaulting Transmission Customer. Billing disputes between the Transmission Provider and the Transmission Customer or other entity shall be addressed through the Transmission Provider's dispute resolution procedures, and shall not relieve the Transmission Customer or other entity of the obligation to make payment of all amounts due hereunder.

If the Transmission Customer fails to meet these requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy, or, in the case of a state required retail access program that provides for continuation of retail service to affected end-use customers by another supplier that is a Transmission Customer, immediately terminate Transmission Service as provided above.

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider, the Transmission Owners, PJMSettlement nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Liability:

Neither the Transmission Provider, a Transmission Owner, PJMSettlement, nor a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Transmission Customer, third party or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any Service Agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of the Transmission Provider, the Transmission Owner, PJMSettlement, or the Generation Owner, as the case may be.

To the extent that a Transmission Customer, third party or other person has a claim against the Transmission Provider, PJMSettlement, a Transmission Owner, or a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider the amount of any judgment or arbitration award on such claim entered in favor of the Transmission Customer, third party or other person shall be limited to the value of the Transmission Provider's assets or the Transmission Owner's assets or the Generation Owner's assets, as the case may be. The Transmission Customer, third party or other person may not seek to enforce any claims against the directors, managers, members, shareholders, officers or employees of the Transmission Provider, a Transmission Owner, or a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider who shall have no personal liability for obligations of the Transmission Provider, a Transmission Owner, or a Generation Owner by reason of their status as directors, managers, members, shareholders, officers or employees of the Transmission Provider or a Transmission Owner or a Generation Owner; provided, however, that nothing herein contained shall affect the obligations of any member of the Transmission Provider or PJMSettlement under the Operating Agreement or this Tariff or any schedule hereunder.

10.3 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save each Transmission Owner, the Transmission Provider, PJMSettlement, and each Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider, and their directors, managers, members, shareholders, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's, PJMSettlement's, a Transmission Owner's, or a Generation Owner's (acting in good faith to implement or comply with the directives of the Transmission Provider) performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by such Transmission Owner, the Transmission Provider, or such Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider.

10.4 Limitation on Claims:

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

(b) For claims that arose prior to the effective date of Section 10.4 of the Tariff, the claimant shall have two years from the effective date to assert such claims.

II. POINT-TO-POINT TRANSMISSION SERVICE

References to section numbers in this Part II refer to sections of this Part II, unless otherwise specified.

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery. PJMSettlement shall be the Counterparty to the Point-To-Point Transmission Service transactions under this Tariff. As set forth in Attachment K, Section D, Point-To-Point Transmission Service transactions may give rise to several component charges and credits, which may offset one another, and such component charges and credits are not separate transactions from Transmission Service transactions.

23.1 Procedures for Assignment or Transfer of Service:

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider and PJMSettlement governing reassignments of transmission service prior to the date on which the reassigned service commences. ~~The Transmission Provider~~PJMSettlement shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider and PJMSettlementor the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

27A Distribution of Revenues from Non-Firm Point-to-Point Transmission Service

Transmission revenues from Non-Firm Point-to-Point Transmission Service (other than the portion of such revenues equal to congestion charges and the revenues attributable to the Transitional Revenue Neutrality Charge) for a Billing Month shall be distributed to the Network Customers (including the Transmission Owners) and Transmission Customers purchasing Firm Point-to-Point Transmission Service in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service. ~~The Transmission Provider~~PJMSettlement shall distribute all revenues attributable to the Transitional Revenue Neutrality Charge to Allegheny Power.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

References to section numbers in this Part III refer to sections of this Part III, unless otherwise specified.

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which each Transmission Owner utilizes the Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff. PJMSettlement shall be the Counterparty to the Network Integration Transmission Service transactions under this Tariff. As set forth in Attachment K, Section D, Network Integration Transmission Service transactions may give rise to several component charges and credits, which may offset one another, and such component charges and credits are not separate transactions from Network Integration Transmission Service transactions.

34 Rates and Charges

The Network Customer shall pay PJMSettlement, in its own name, or as agent for the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, PJM Administrative Service, any applicable Transmission Enhancement Charge(s) and applicable study costs, consistent with Commission policy, along with the following:

119 Cost of Service Recovery Rate:

Notwithstanding anything to the contrary in Part V of this Tariff, a Generation Owner with a generating unit proposed for Deactivation that continues operating beyond its proposed Deactivation Date may file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V ("Cost of Service Recovery Rate"). In the event that the Generation Owner or its Designated Agent files a rate pursuant to this section 119, the Generation Owner shall not be eligible to receive Deactivation Avoidable Cost Credits or any compensation pursuant to section 117 of this Tariff, except as provided pursuant to this section 119, and ~~Transmission Provider~~PJMSettlement shall pay the Generation Owner the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving Deactivation Avoidable Cost Credits, prior to filing an Cost of Service Recovery Rate, such Deactivation Avoidable Cost Credits will cease as of the date that the Generation Owner or its Designated Agent files its Cost of Service Recovery Rate, and ~~the Transmission Provider~~PJMSettlement shall begin paying the Generation Owner or its Designated Agent the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving compensation pursuant to section 117 of this Tariff, prior to filing an Cost of Service Recovery Rate, such compensation shall continue until the effective date established by the Commission for the Cost of Service Recovery Rate.

A generating resource owner shall direct all inquiries regarding avoidable expenses to the Market Monitoring Unit. If a generating resource owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may petition the Commission for an order that would require the generating resource owner to include an appropriate cost component. This provision is duplicated in section IV.2 of Attachment M – Appendix.

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company	0.0797
Duquesne Light Company[1]	0.0520

1Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region:

$0.1019/MWh

Each month, ~~the Transmission Provider~~PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	0.50
Baltimore Gas and Electric Company	0.80
Delmarva Power & Light Company	0.77
PECO Energy Company	2.68
PP&L, Inc. Group	1.36
Potomac Electric Power Company	0.33
Public Service Electric and Gas Company	2.64
Jersey Central Power & Light Company	1.30
Metropolitan Edison Company	0.43
Pennsylvania Electric Company	0.66
Rockland Electric Company	0.20
Commonwealth Edison Company	37.62
AEP East Operating Companies	47.90
The Dayton Power and Light Company	2.36
Duquesne Light Company	0.45

SCHEDULE 2
Reactive Supply and Voltage Control from
Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in section 3.2.3B of the Appendix to Attachment K.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation or other source Owner Monthly Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation or other source Owner Monthly Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation or other source Owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation or other source Owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source Owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity in the month (not curtailed by PJM) divided by 24.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

Each month, the Transmission Provider shall pay each Generation or other source Owner an amount equal to the Generation or other source Owner's monthly revenue requirement as accepted or approved by the Commission. In the event a Generation or other source Owner sells a Generation Capacity Resource(s) which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation or other source Owner's Zone may be allocated as agreed to by the owners of Generation Capacity

Resources in that Zone. Such Generation or other source Owners shall inform Transmission Provider of any such agreement. In the absence of agreement among such Generation or other source Owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

SCHEDULE 3
Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. The Transmission Provider shall administer the purchases of Regulation Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Regulation Service in the PJM Interchange Energy Market; 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 of generation resources by a customer to satisfy its Regulation obligation.

For regulation not satisfied by individual Transmission Owners on behalf of their Native Load Customers, Network Customers or other Transmission Customers serving load in the PJM Region, the Transmission Provider will order the lowest cost alternative for regulation in service as needed to meet the regulation requirements of each Regulation Zone (as set forth in the PJM Manuals), as specified below:

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from generators located within the metered electrical boundaries of such Regulation Zone. Generators offering regulation shall comply with applicable standards and requirements for regulation capability and dispatch specified in the procedures of the Office of the Interconnection.

b. The Office of the Interconnection shall obtain and maintain an amount of regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its procedures.

c. The regulation range of a unit shall be at least twice the amount of regulation assigned.

d. A unit capable of automatic energy dispatch that is also providing regulation shall have its energy dispatch range reduced from the regulation range by twice the amount of the regulation provided. The amount of regulation provided by a unit shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the amount of regulation shall be added to the unit's normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.

e. Qualified regulation must satisfy the verification tests described in the procedures of the Office of the Interconnection.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its regulation obligation from its own resources capable of performing regulation service, by contractual arrangements with others able to provide regulation service on a comparable basis, or by purchases from, as applicable, the regulation market in the MAAC Control Zone, the regulation market in the VACAR Control Zone or the regulation market in the PJM West Region.

g. The Office of the Interconnection shall obtain regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Control Zone requirements not otherwise satisfied by a Transmission Owner, Network Customer or other Transmission Customer, in accordance with Section 1.11.4(b) of Attachment K-Appendix.

h. The Office of the Interconnection shall dispatch resources for regulation by sending regulation signals and instructions to resources from which regulation service has been offered, in accordance with the procedures of the Office of the Interconnection. Those resources 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. Those providing regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

i. Each Transmission Owner (on behalf of its Native Load Customers), Network Customer or other Transmission Customer serving load within a Control Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Control Zone for such hour, based on the entity's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Control Zone for such hour.

j. An entity supplying regulation at the direction of the Office of the Interconnection in excess of its hourly regulation obligation shall be credited for each increment of such regulation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix. A Transmission Owner, Network Customer or other Transmission Customer that does not meet its hourly regulation obligation shall be charged for regulation dispatched by the Office of the Interconnection to meet such obligation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix.

SCHEDULE 4
Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner, Transmission Customer, and Network Customer must purchase Energy Imbalance Service through the Transmission Provider, with PJMSettlement acting as the Counterparty, or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service. For purposes of Energy Imbalance Services, if a Point of Delivery serves more than one Transmission Owner or Network Customer, the Energy Imbalance Service and any associated charges will be computed by the Transmission Provider for the Point of Delivery and the allocation of the service and associated charges shall be the responsibility of the meter operator of the Point of Delivery.

For each Transmission Owner, Transmission Customer receiving service under Part II of this Tariff,~~.~~ and Network Customer, Energy Imbalance Service is considered to be PJM interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of this Tariff. The Transmission Provider shall administer the purchases by customers of Energy Imbalance Service. PJMSettlement shall be the Counterparty to the purchases by customers of Energy Imbalance Service.

SCHEDULE 5
Operating Reserve - Synchronized Reserve Service

Synchronized Reserve Service is needed to serve load immediately in the event of a system contingency. Synchronized Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service or eligible Demand Resources. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner and Network Customer must purchase this service from the Transmission Provider. The amount of and charges for Synchronized Reserve Service, as defined in accordance with NERC operating policies, will be accounted and paid for as set forth in Section 3.2.3A of the Appendix to Attachment K. The Transmission Provider shall administer the purchases by customers of Synchronized Reserve Service. PJMSettlement shall be the Counterparty to the purchases by customers of Synchronized Reserve Service in the PJM Interchange Energy Market; 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 of generation resources by a customer to satisfy its Synchronized Reserve obligation.

SCHEDULE 6
Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner and Network Customer must purchase this service from the Transmission Provider. The amount of and charges for Supplemental Reserve Service will be accounted and paid for as part of the Operating Reserves in accordance with sections 3.2.3 and 3.2.3A.01 of the Appendix to Attachment K. The Transmission Provider shall administer the purchases by customers of Supplemental Reserve Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Supplemental Reserve Service in the PJM Interchange Energy Market; 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 Supplemental Reserve.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service ~~from~~ through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider, in conjunction with the Transmission Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5 or 6 below.

5. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall

commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in section 18, and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

6A. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6.

Performance Standards and Outage Restrictions

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to

two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its commitment pursuant to section 5 or section 6, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6A.

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6, as applicable, or (ii) the formulas set forth in section 18 of this Schedule 6A for the commitment term set forth in section 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. Requests for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to section III of Attachment M – Appendix and the PJM Manuals. The Market Monitoring Unit and the generator owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements. The Black Start Service generator owner may submit Black Start Service revenue requirements that it chooses, provided that (i) it has participated in good faith with the process described in this section and in section III of Attachment M - Appendix, (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Service generator owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff.

In the event that the Black Start Service generator owner and Market Monitoring Unit cannot agree on the level of each component included in the calculation of the Black Start Service revenue requirements, and the Black Start Service generator owner submits its own values to the

Office of the Interconnection that are inconsistent with the Market Monitoring Unit's determination, the Office of the Interconnection shall determine whether to accept such values subject to the requirements of the Tariff and the PJM Manuals. If the Office of the Interconnection does not accept the values submitted by the Black Start Service generator owner in such case, the Black Start Service generator owner may file its proposed values with the Commission for approval. Pursuant to section III of Attachment M - Appendix, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Service generator owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission. No change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months. ~~PJM~~ The Transmission Provider will presume that any FERC-approved cost recovery plan would be the exclusive basis for the recovery of a Black Start Unit's recovery of its costs during the applicable term.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

where:

Fixed BSSC

Black Start Units with a commitment established under section 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following formula:

CONE * 365 * Black Start Unit Capacity * X

Where:

"CONE" is the then current net Cost of New Entry for the CONE Area where the Black Start Unit is located as set forth in Section 5.10 of Attachment DD.

"Black Start Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW.

X is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start

Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under section 5, X shall be .01 for Hydro units, .02 for Diesel or CT units.

Black Start Units with a commitment established under section 6 above shall calculate Fixed BSSC or “Fixed Black Start Service Costs” in accordance with the following formula:

Black Start Capital Cost * CRF

Where:

“Black Start Capital Costs” is the capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit.

“CRF” or “Capital Recovery Factor “ is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table:

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Variable BSSC

All Black Start Units shall calculate Variable BSSC or “Variable Black Start Service Costs” in accordance with the following formula:

Black Start Unit O&M * Y

Where:

“Black Start Unit O&M” are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Task Force Manual. Such costs shall include those incurred by a

Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

“Y” is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit’s O&M costs on the unit’s cost-based energy schedule, calculated based on the Cost of Element Guidelines in the PJM Manauls.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall cacluate Fuel Storage Costs or “FSC” as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

“Fuel Burn Rate” is actual fuel burn rate for the Black Start Unit.

“12-Month Forward Strip” is the average of forward prices for the fuel burned in the Black Start Unit.
“Basis” is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.
“Bond rate” is the value determined with reference to the Moody's Utility Index for bonds rated Baa1.
“MTSL” is the “minimum tank suction level” and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor for Black Start Units with a commitment established under section 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

Credits

20. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units.

21. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

22. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider and Applicable Regional Reliability Council criteria for Black Start Service and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

23. Zonal rates will be based on Black Start Service capability of generation units nominated by each transmission zone and allocated to network service customers and point-to-point reservations.

24. Revenue requirements for Black Start Units nominated by a Transmission Owner as critical (regardless of zonal location) will be allocated to the nominating Transmission Owner's zone.

25. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity in the month (not curtailed by PJM) divided by 24.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone 5/	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone					

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all 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. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse ~~the Transmission Provider~~PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-

on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 11
[Reserved]~~Transitional Market Expansion Charge~~

~~(a) In recognition of the benefits to competition and system reliability from the expansion of the PJM markets and system operations to include the PJM West Region, and the relative rate savings under Schedule 9 of this Tariff occasioned thereby, Generation Providers (as defined in Schedule 9-3) and customers using Point-to-Point and Network Integration Transmission Service shall pay a Transitional Market Expansion Charge, as defined below.~~

~~(b) Except as provided in Section (f) below, PJM will charge each customer using Point-to-Point or Network Integration Transmission Service each month a charge equal to $0.0381 times the total quantity in Mwhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region or for export from such area (including deliveries at the boundary of such area for Wheeling-Through Service, as that term is defined in Schedule 9-3) during such month by such customer.~~

~~(c) Except as provided in Section (f) below, PJM will charge each Generation Provider each month a charge equal to $0.0070 times the total quantity in Mwhs of energy input into the Transmission System (including receipts into the Transmission System for Wheeling-Through Service) during such month by such Generation Provider.~~

~~(d) PJM shall distribute all revenues collected under this schedule each calendar month to Allegheny Power.~~

~~(e) The charge provided for under this Schedule 11 shall terminate effective on the day on which the sum total of the revenues collected under this charge and under the Transitional Revenue Neutrality Charges under Schedule 7 and Schedule 8 equals $84,993,360.~~

~~(f) The charges set forth in this Schedule 11 will not apply to energy either delivered to load or input into the Transmission System in the future PJM Zones comprised of Commonwealth Edison and Commonwealth Edison Company of Indiana, Inc.; The Dayton Power and Light Company; American Electric Power Service Corporation and its affiliates, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company; or Duquesne Light Company.~~

SCHEDULE 12
Transmission Enhancement Charges

(a) Establishment of Transmission Enhancement Charges. One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements (as defined in Section 1.38C of the Tariff) by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. ("Coordinated System Plan"). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates ~~Transmission Provider~~PJMSettlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan or the Coordinated System Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

(1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;

(2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC's rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or

(3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a "Transmission Enhancement Charge." Transmission Enhancement Charges of one or more Transmission Owners shall be established in accordance with this Schedule 12. Transmission Enhancement Charges of one or more transmission owners within the Midwest Independent System Operator, Inc. ("MISO") shall be determined in accordance with to the MISO Tariff.

(b) Designation of Customers Subject to Transmission Enhancement Charges.

(i) Regional Facilities and Necessary Lower Voltage Facilities. Transmission Provider shall assign on a region-wide basis cost responsibility for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are (1) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that operate at or above 500 kV ("Regional Facilities"), or (2) new

Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan ("Necessary Lower Voltage Facilities") as follows:

(A) Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated annually among Responsible Customers as defined in this Schedule 12 on an annual load-ratio share basis using, consistent with section 34.1 of the Tariff, the applicable zonal loads at the time of each Zone's annual peak load from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.

(B) Cost responsibility allocated to an owner of a Merchant Transmission Facility pursuant to subsection (A) above shall be based on the Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility or on the planned Firm Transmission Withdrawal Rights associated with its Merchant Transmission Facility for which it has executed an Interconnection Service Agreement.

(C) (1) Except for transformers that are an integral component of a Regional Facility, transformers with low-side voltages below 500 kV shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that operate below 500 kV and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.

(D) Transmission Provider shall designate in the Schedule 12-Appendix the cost responsibility allocations determined pursuant to this subsection (b)(i) of this Schedule 12.

(ii) Cost Responsibility Assignment Procedures For Other Facilities Pursuant To Settlement In Docket Nos. ER06-456-000, et al. Pursuant to Schedule 6 of the Operating Agreement, Transmission Provider is required to assign cost responsibility for Required Transmission Enhancements based on the Transmission Provider's assessment of the contributions to the need for, and benefits expected to be derived from, each Required Transmission Enhancement. In Docket Nos. ER06-456-000, et al., the FERC approved a "Settlement Agreement And Offer Of Partial Settlement" filed on September 14, 2007, ("Docket No. ER06-456 Settlement"), that among other things provides procedures and methodologies for Transmission Provider to assign cost responsibility in accordance with Schedule 6 of the Operating Agreement for (1) Lower Voltage Facilities as defined in subsection (b)(iii) of this Schedule 12, (2) below 500 kV spare parts, replacement equipment, and circuit breakers and associated equipment, and (3) economic-based Required Transmission Enhancements that as planned will operate below 500 kV (collectively "Applicable Facilities"). The procedures set forth in subsections (b)(iii), (iv), (v) and (vi) of this Schedule 12 shall apply to (1) the assignments of cost responsibility for Applicable Facilities filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, and (2) the assignment of cost responsibility for Applicable Facilities included in Regional Transmission Expansion Plans approved by the PJM Board after June 1, 2007, unless and until a different method for determination of cost responsibility assignments is allowed into effect by the FERC. Notwithstanding any otherwise applicable filed rate and prior notice requirements of the Federal Power Act, in accordance with the Docket No. ER06-456 Settlement, the assignments of cost responsibility determined by Transmission Provider pursuant to subsections (b)(iii), (iv), (v) and (vi) of this Schedule 12 as reflected in Schedule 12-Appendix to the Tariff are subject to refunds, surcharges, and interest calculated pursuant to 18 C.F.R. § 35.19a, if and as required by FERC, based on an order on the hearing concerning issues applicable to Merchant Transmission Facilities established in PJM Interconnection, L.L.C., 119 FERC ¶ 61,067 (2007). The treatment of Merchant Transmission Facilities in the distribution factor or "DFAX" analysis described in subsection (b)(iii) of this Schedule 12, including but not limited to, the use of "Interim Values" (fifty percent of existing or planned Firm Withdrawal Rights of a Merchant Transmission Facility for the purposes of modeling a Merchant Transmission Facility in the determination of cost responsibility assignments for an "Interim Period" pending the outcome of the hearing on issues applicable to Merchant Transmission Facilities) is subject to all provisions of the Docket No. ER06-456 Settlement, and is specifically without prejudice to any position a party may take at the hearing described above and is not intended to influence the outcome of such hearing or to authorize in any way for any other purpose the Interim Values that are used during the Interim Period as part of the Docket No. ER06-456 Settlement.

(iii) Lower Voltage Facilities. Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues; (b) as planned will operate below 500 kV; and (c) are not "Necessary Lower Voltage Facilities" as defined in section (b)(i) of this Schedule 12 (collectively "Lower Voltage Facilities"), as follows:

(A) Cost responsibility for a Lower Voltage Facility shall be assigned pursuant to subsection (b)(iii)(C) of this Schedule 12 when the good faith estimate of the cost of the Lower Voltage Facility prepared in connection with the development of the Regional Transmission Expansion Plan and provided to the PJM Board at the time the Lower Voltage Facility is included for the first time in the Regional Transmission Expansion Plan equals or exceeds $5 million. The determination of whether the estimated costs of a Lower Voltage Facility equals or exceeds this threshold shall be based solely on such good faith estimate of the cost of the Lower Voltage Facility, regardless of the actual costs incurred. For the purpose of applying this $5 million threshold, the estimated cost of a Lower Voltage Facility shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the same time for inclusion in the Regional Transmission Expansion Plan that collectively are intended to mitigate a specific reliability criteria violation or set of related violations.

(B) Cost responsibility for a Lower Voltage Facility, the estimated costs of which do not equal or exceed the $5 million threshold described in subsection (b)(iii)(A) of this Schedule 12, shall be assigned to the Zone where the Lower Voltage Facility is to be located. In the event that a Lower Voltage Facility, the estimated costs of which do not equal or exceed the $5 million threshold, consists of a single transmission element or multiple transmission elements to be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of the transmission elements located in such Zone. Merchant

Transmission Facilities shall not be assigned cost responsibility for Lower Voltage Facilities the estimated costs of which do not equal or exceed the $5 million threshold.

(C) To assign cost responsibility for Lower Voltage Facilities, the estimated costs of which equal or exceed the $5 million threshold described in subsection (b)(iii)(A) of this Schedule 12, Transmission Provider shall use the DFAX analysis described in this subsection (b)(iii)(C) of Schedule 12 that takes into account the contributions of loads and Merchant Transmission Facilities to the reliability criteria violations for which Lower Voltage Facilities are identified as solutions.

(1) For purposes of the assignment of cost responsibility under this section (b)(iii)(C) of Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the effect of the load of each Zone or Merchant Transmission Facility on the transmission constraint that requires the Lower Voltage Facility, as determined by a power flow analysis. In general, a distribution factor can be represented as:

Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility

Pre-shift power flow = Megawatt flow over the constrained transmission element before the incremental megawatt transfer

After-shift power flow = Megawatt flow over the constrained transmission element after the incremental megawatt transfer

When calculating such distribution factors:

(a) All distribution factors are calculated with respect to a constrained transmission facility that has been modeled to exceed its capability in violation of reliability criteria or to address operational adequacy and performance issues, requiring the addition of the Lower Voltage Facility identified in the Regional Transmission Expansion Plan to resolve the identified violation(s). The distribution factor is calculated for the transmission facility prior to the addition of the reinforcements identified to resolve the violation(s).

(b) Contributions to a criteria violation are determined based on distribution factors to the aggregate load within a Zone or, in the case of a Merchant Transmission Facility, distribution factors determined to the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(c) In the event that a violation is modeled to occur with one or more transmission facilities removed from service, the distribution factor will be calculated with these facilities removed from service.

(d) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a constrained transmission facility to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(e) All values and inputs used in the calculation of the distribution factor shall be the same values and inputs as used in the basecase for the Regional Transmission Expansion Plan.

(2) In the DFAX analysis, to determine the impact of zonal loads and Merchant Transmission Facilities on a constrained facility, Transmission Provider shall calculate a distribution factor for each Zone and each Merchant Transmission Facility by modeling a transfer from all generation in the PJM Region (a) individually to the loads in each Zone and (b) individually to each Merchant Transmission Facility based on (i) an Interim Value as specified in the Docket No. ER06-456 Settlement of fifty percent of its associated existing or planned Firm Transmission Withdrawal Rights, as applicable, identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility, or (ii) such other value if any at all (referred to herein as a "Final Value") as determined to be appropriate by the FERC based on the outcome of the hearing on the issues applicable to Merchant Transmission Facilities in Docket Nos. ER06-456-000, et al. To establish the impact of the zonal load or Merchant Transmission Facility, in megawatts, on a constrained facility, the distribution factor on a constrained facility associated with the resulting transfer modeled by the Transmission Provider to an individual Zone or a Merchant Transmission Facility shall be multiplied, as applicable, by (c) zonal peak load of the Zone being evaluated or (d) the Interim Value, or Final Value if any, as applicable, applied to (i) the existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility, for a Merchant Transmission Facility that is not yet in service. The products, so determined, for each Zone and each Merchant Transmission Facility, shall determine the relative allocation shares for each Zone and each Merchant Transmission Facility.

(3) In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

(4) In the DFAX analysis, Transmission Provider shall calculate assignments of cost responsibility based on all reliability criteria violations that contribute to the need for a Lower Voltage Facility. If one Lower Voltage Facility or group of Lower Voltage Facilities resolves multiple violations, to determine a Zone or Merchant Transmission Facility's

cost responsibility for such facility, the Zone's and Merchant Transmission Facility's individual megawatt contribution to each reliability criteria violation (determined in subsection (b)(iii)(C)(2) of this Schedule 12) shall be proportionally scaled up or down, so that the sum of the adjusted megawatt impacts equals the magnitude of the overload (the "overload" meaning the megawatt flow on the transmission element exceeding the applicable rating therefore violating the reliability criteria, as modeled in the Regional Transmission Expansion Plan). The Zone's or Merchant Transmission Facility's cost responsibility assignment shall be calculated as the ratio of (i) the sum of the contributions, in megawatts, of that Zone or Merchant Transmission Facility, to each of the reliability criteria violations, to (ii) the sum of the overloads, in megawatts, on the constrained facilities that are the subject of the reliability criteria violations. The foregoing notwithstanding, for the cost responsibility assignments for Lower Voltage Facilities already filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, Transmission Provider shall consider only the single worst reliability criteria violation associated with each Lower Voltage Facility.

(5) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Zones and Merchant Transmission Facilities to reflect (a) the boundaries of Locational Deliverability Areas ("LDAs"), as defined in Attachment DD to the Tariff, and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective ("CETO"), as defined in Attachment DD to the Tariff, associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. The contribution of each zonal load to the constraint shall be determined by multiplying the resulting distribution factor by the peak load of a Zone or an Interim Value or Final Value if any, as specified in subsection (b)(iii)(C)(2) of this Schedule 12, for a Merchant Transmission Facility, as applicable. For Zones and Merchant Transmission Facilities that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Zones or Merchant Transmission Facilities as above for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Zone or Merchant Transmission Facility in the calculation of the contribution to the constrained facility. A distribution factor threshold of 0.001 shall be applied to all cost responsibility assignment calculations such that any distribution factor less than 0.001 shall be set equal to zero.

(6) In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the ER06-456 Settlement.

(7) Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii)(C) of this Schedule 12 to the nearest one-hundredth of one percent.

(8) Transmission Provider shall not account for the ability to adjust use of phase angle regulators ("PARs") in the DFAX analysis described in subsection (b)(iii)(C) of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(iv) Below 500 kV Spare Parts, Replacement Equipment And Circuit Breakers. Transmission Provider shall assign cost responsibility for below 500 kV spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) Below 500 kV spare parts that are part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV spare parts independently included the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection shall be assigned to the Zone of the owner of the spare part.

(B) Below 500 kV replacement equipment that is part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) Below 500 kV circuit breakers and associated equipment that are part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment.

(v) Economic-Based Required Transmission Enhancements That As Planned Will Operate Below 500 kV. Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV as follows:

(A) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and are accelerations of reliability-based Required Transmission Enhancements as described in section 1.5.7(b)(i) of Schedule 6 of the Operating Agreement ("Acceleration Projects") by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii)(C) of this Schedule 12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices ("LMP Benefit") over the period that the reliability-based enhancement or expansion is to be accelerated ("LMP Benefits Methodology"). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement that as planned will operate below 500 kV equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the reliability-based Required Transmission Enhancement is accelerated (i.e. the period between the date the Required Transmission Enhancement actually goes into service and the date the Required Transmission Enhancement originally was scheduled to go in service as a Lower Voltage Facility in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the reliability-based Required Transmission Enhancement is accelerated, cost responsibility for such an Acceleration Project shall be assigned based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12. Subject to an order on the hearing noted in section (b)(ii) of this Schedule 12, the assignment of any cost responsibility for Acceleration Projects to a Merchant Transmission Facility shall be based upon its Interim Values or Final Value if any, as applicable.

(B) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and that are modifications to reliability-based Required Transmission Enhancements as described in section 1.5.7(b)(ii) of Schedule 6 of the Operating Agreement based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12.

(C) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and are new enhancements or expansions that could relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement based on a Change in Load Energy Payment consistent with the methodology set forth in section 1.5.7(d) of Schedule 6 of the Operating Agreement. Cost responsibility shall be allocated based on each Zone's pro rata share of the Change in Load Energy Payment. The Change in Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in Load Energy Payment.

(vi) Finality of Cost Responsibility Assignment. Once a Lower Voltage Facility or an economic-based Required Transmission Enhancement that as planned will operate below 500 kV is included in the Regional Transmission Expansion Plan, any modification to the Lower Voltage Facility or economic-based Required Transmission Enhancement that as planned will operate below 500 kV, respectively, that subsequently is included in the Regional Transmission Expansion Plan shall be considered a separate additional project subject to its own cost responsibility assignment. Such subsequent modification shall not impact or be impacted by the cost responsibility assignments that already have been made for the previously approved Lower Voltage Facility or economic-based Required Transmission Enhancement, as applicable.

(vii) FERC Filing. Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Section 1.6 of Schedule 6 of the PJM Operating Agreement, the Transmission Provider shall designate in the Schedule 12-Appendix and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge ("Responsible Customers") based on the cost responsibility assignments determined pursuant to subsections (b)(i) through (v) of this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those made for the relevant Regional Facility, Necessary Lower Voltage Facility, Lower Voltage Facility, and economic-based Required Transmission Enhancement that as planned will operate below 500 kV in the Regional Transmission Expansion Plan or in the Coordinated System Plan.

(viii) MISO. For purposes of this Schedule 12, where the Responsible Customers are subject to the Open Access Transmission and Energy Markets Tariff for the Midwest Independent System Operator, Inc. (“MISO Tariff”), MISO shall be the Responsible Customer with respect to all such Required Transmission Enhancements. Cost responsibility with respect to Transmission Enhancement Charges for which MISO has been designated the Responsible Customer shall be allocated within MISO in accordance with the MISO Tariff.

(ix) Merchant Transmission Facilities. For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(c) Determination of Transmission Enhancement Charges. In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner’s annual transmission revenue requirement associated with the Required Transmission Enhancement;

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible;

(3) A Transmission Owner’s annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC’s rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner’s rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements; and

(4) Each Transmission Enhancement Charge assigned by the Transmission Provider to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Section 34.1 of the PJM Tariff. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge assigned by the Transmission Provider to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Section 25 of the PJM Tariff.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to Section (b) of this Schedule shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in Section (a), the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

(d) Recovery of Transmission Enhancement Charges.

(1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.

(2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to MISO in the case of Transmission Enhancement Charges established by one or more transmission owners within MISO to be distributed to said transmission owners in accordance with the MISO Tariff.

(e) Crediting of Revenue from Transmission Enhancement Charges. In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

EXHIBIT A TO SCHEDULE 14

Form of Service Agreement for
<u>Transmission Service over the Neptune Line</u>

1.0 This Service Agreement, dated as of ___________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider"), as administrator of Transmission Service over the Neptune Line, -and _________________________ ("Neptune Transmission Customer").

2.0 The Neptune Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Neptune Reservation under the Tariff.

3.0 If required, the Neptune Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Neptune Transmission Customer agrees to take and pay for the Neptune Reservation in accordance with the provisions of Schedule 14 of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

<u>Transmission Provider</u>
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

<u>Neptune Transmission Customer</u>

____

____

____

7.0 The Tariff, including Schedule 14, is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: ______________________ ____________________ __________________
Name Title Date

Neptune Transmission Customer:

By: ______________________ ____________________ __________________
Name Title Date

CERTIFICATION

I, ____________________, certify that I am a duly authorized officer of ______________________________ (Neptune Transmission Customer) and that ______________________________ (Neptune Transmission Customer) will not request service under this Service agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this ________ day of ______________, ____________.

____
(Notary Public)

My Commission expires: ______________________________

Specifications For Transmission Service Over Neptune Line

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted.

____

3.0 Point of Receipt: Raritan River (Sayreville) Substation in Sayreville, New Jersey

Delivering Party: ____

4.0 Point of Delivery: Newbridge Road Substation in Long Island, New York

Receiving Party: ____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability):
____

6.0 Designation of party(ies) subject to reciprocal service obligation: ________________

____

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff and Schedule XX).

8.1 Neptune Reservation Charge: ______________________________________

____

8.2 Neptune Service Administration Charges: ____________________________

____

EXHIBIT A TO SCHEDULE 16

Form of Service Agreement for
Transmission Service over the Linden VFT Facility

1.0 This Service Agreement, dated as of ____________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider"), as administrator of Transmission Service on the Linden VFT Facility, and ____________________________ ("Linden VFT Transmission Customer").

2.0 The Linden VFT Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Linden VFT Reservation under the Tariff.

3.0 If required, the Linden VFT Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Linden VFT Transmission Customer agrees to take and pay for the Linden VFT Reservation in accordance with the provisions of Schedule 16 of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497
Linden VFT Transmission Customer ___________________________________ ___________________________________ ___________________________________

7.0 The Tariff, including Schedule 16, is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: ________________________ ________________________ ____________________
Name Title Date

Linden VFT Transmission Customer:

By: ________________________ ________________________ ____________________
Name Title Date

CERTIFICATION

I, ____________________, certify that I am a duly authorized officer of ________________________________ (Linden VFT Transmission Customer) and that ________________________________ (Linden VFT Transmission Customer) will not request service under this Service agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this ________ day of ______________, ____________.

____
(Notary Public)
My Commission expires: ______________________________

Specifications For Transmission Service Over Linden VFT Facility

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted.

____

3.0 Point of Receipt: VFT Switching Station in Linden, New Jersey

Delivering Party: ____

4.0 Point of Delivery: NYISO (at the Linden Cogen 345 kV ring bus in Linden, New Jersey)

Receiving Party: ____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability):
____

6.0 Designation of party(ies) subject to reciprocal service obligation: __________________

____

____

____

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff and Schedule16).

7.1 Linden VFT Reservation Charge:
____

____

7.2 Linden VFT Service Administration Charges:
____

____

7.3 Linden VFT Transmission Enhancement Charges:

____

____

ATTACHMENT A

Form of Service Agreement For
Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between the Office of the Interconnection of PJM Interconnection L.L.C. (the Transmission Provider) as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Firm Point-To-Point Transmission Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities, Local Upgrades and/or Network Upgrades and any contingencies identified in the Upgrade Construction Service Agreement by and among Transmission Provider, Transmission Customer and ________[name of transmission owner constructing upgrades]________________ are completed, if applicable, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties or as otherwise specified in this Service Agreement.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty)

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

____

____

____

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

8.0 For Short-Term Firm Point-To-Point Transmission Service requested under this Agreement, the confirmation procedures set forth in this section 8.0 shall apply. Whenever PJM notifies the Transmission Customer that a request for Short-Term Firm Point-To-Point Transmission Service can be accommodated, the Transmission Customer shall confirm, by the earlier of (i) 15 days after PJM approves the request for service, or (ii) 12:00 noon on the day before the Service Commencement Date, that it will commence the requested service. Failure of the Transmission Customer to provide such confirmation will be deemed a withdrawal and termination of the request for the service, and any deposit submitted with the request will be refunded with interest.

{Use the following Section 9.0 for Long-Term Firm Point-To-Point Transmission Service Requests that require construction of Direct Assignment Facilities, Local Upgrades, and/or Network Upgrades}

9.0 The Transmission Customer was notified by the Transmission Provider that the System Impact Study indicates that Firm Point-To-Point Transmission Service can not extend beyond one year from the commencement of service unless certain Direct Assignment Facilities, Local Upgrades, and/or Network Upgrades are constructed pursuant to the Tariff and in accordance with the terms and conditions of the Upgrade Construction Service Agreement by and among Transmission Provider, Transmission Customer, and __________________[name of Transmission Owner constructing upgrades]________. The required Local Upgrades, Network Upgrades and/or Direct Assignment Facilities are identified, including estimated costs and lead times to support the requested Firm Point-To-Point Transmission Service in that Upgrade Construction Service Agreement. Therefore, the Transmission Customer may not be able to exercise reservation/rollover priority rights, in whole or in part, which it may otherwise have pursuant to Section 2.2 of the Tariff upon the initial termination date of the Firm-Point-To-Point Transmission Service, unless and until the Local Upgrades, Network Upgrades and/or Direct Assignment Facilities are completed pursuant to the terms of the Upgrade Construction Service Agreement.

10.0 Rates for Long-Term Firm Point-To-Point Transmission Service shall apply pursuant to this Service Agreement and applicable provisions of the PJM Tariff. Transmission Customer will not be eligible for any credits against these rates for the value of the Local Upgrades, Network Upgrades and/or Direct Assignment Facilities it provides; its consideration for payment for Customer-Funded Upgrades will be the Long-Term Firm Point-To-Point Transmission Service described in the Transmission Service Agreement, and the associated Upgrade-Related Rights, as described in the Upgrade Construction Service Agreement.

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

Office of the Interconnection:

By: __________________________ __________________ _________________

Name Title Date

Counterparty:

By: __________________________ __________________ _________________

Name Title Date

Transmission Customer:

By: __________________________ __________________ _________________

Name Title Date

CERTIFICATION

I, ______________________, certify that I am a duly authorized officer of _________________________________ (Transmission Customer) and that _________________________________ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this ______ day of ________________, ________.

____
(Notary Public)

My Commission expires:________________________

Specifications For Long-Term Firm Point-To-Point
Transmission Service

l.0 Term of Transaction: ______________________________

Start Date: ______________________________

Termination Date: ______________________________

2.0 Description of capacity and energy to be transmitted including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________

Delivering Party: ______________________________

4.0 Point(s) of Delivery: ______________________________

Receiving Party: ______________________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Transmission Capability): ______________________________

6.0 Designation of party(ies) subject to reciprocal service obligation: ______________________________
____
____
____

7.0 Name(s) of any Intervening Systems providing transmission service: ______________________________
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ______________________________
____

8.2 System Impact and/or Facilities Study Charge(s):
____
____

8.3 Direct Assignment Facilities Charge:_________________________

____

8.4 Ancillary Services Charges: _________________________________

____

____

____

____

____

____

8.5 Other Supporting Facilities Charge:__________________________

____

____

ATTACHMENT A-1

Form Of Service Agreement For
The Resale, Reassignment Or Transfer Of
Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ____________ (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Counterparty:

____

____

____

Assignee:

____

____

____

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

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

Transmission Provider:

By:______________________________ ________________________ ________________

Name	Title	Date

Counterparty:

By:______________________________ ________________________ ________________

Name	Title	Date

Assignee:

By:______________________________ ________________________ ________________

Name	Title	Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ______________________________________

Start Date: ____

Termination Date: _______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:___________________________________

Delivering Party:_______________________________________

4.0 Point(s) of Delivery:__________________________________

Receiving Party:______________________________________

5.0 Maximum amount of reassigned capacity: __________________

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:____________________

____

8.4 Ancillary Services Charges: ______________________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

ATTACHMENT B
Form of Service Agreement For Non-Firm Point-To-Point
Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty):

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

____

____

____

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

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

Office of the Interconnection:

By: ______________________________ __________________ _______________
Name Title Date

Counterparty:

By: ______________________________ __________________ _______________

Name Title Date

Transmission Customer:

By: ______________________________ __________________ _______________
Name Title Date

CERTIFICATION

I, _______________________________, certify that I am a duly authorized officer of ____ (Transmission Customer) and that ____ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this _____ day of ______________, _______.

____
(Notary Public)

My Commission expires:________________________

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a valid request for Network Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff.

3.0 Service under this agreement shall commence on the later of: (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Transmission Service in accordance with the provisions of the Tariff, including the Network Operating Agreement (which is incorporated herein by reference), and this Service Agreement as they may be amended from time to time.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty):

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

____

____

____

6.0 The Tariff for Network Integration Transmission Service is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: ______________________ ________________ ______________
Name Title Date

Counterparty:

By: ______________________ ________________ ______________
Name Title Date

Transmission Customer:

By: ______________________ ________________ ______________
Name Title Date

CERTIFICATION

I, ____________________________, certify that I am a duly authorized officer of ____________________________________ (Transmission Customer) and that ____________________________________ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this _____ day of _____________, _______.

____

(Notary Public)

My Commission expires:_____________________

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

l.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and/or energy to be transmitted within the PJM Region (including electric control area in which the transaction originates).

____

3.0 Network Resources:____

4.0 Network Load:____

5.0 Designation of party subject to reciprocal service obligation:
____

6.0 Name(s) of any Intervening Systems providing transmission service:
____

____

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the tariff.)

7.1 Embedded Cost Transmission Charge:________________________

____

7.2 Facilities Study Charge:________________________

____

7.3 Direct Assignment Facilities Charge:________________________

____

7.4 Ancillary Services Charge:________________________

____

7.5 Other Supporting Facilities Charge:______________________

____

ATTACHMENT F-1

Form of Umbrella Service Agreement for
Network Integration Transmission Service
<u>Under State Required Retail Access Programs</u>

1.0 This Service Agreement dated as of __________, including the Specifications For Network Integration Transmission Service Under State Required Retail Access Programs attached hereto and incorporated herein, is entered into, by and between PJM Interconnection, L.L.C. ("Transmission Provider") as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ________________________, a transmission customer participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service ("Network Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff to the extent necessary to obtain service with respect to its participation in a state required retail access program.

3.0 Service under this Service Agreement shall commence on ________________, and shall terminate on such date as mutually agreed upon by the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

4.0 The Transmission Provider agrees to provide, and the Network Customer agrees to take, Network Integration Transmission Service in accordance with the Tariff, including the Operating Agreement of the PJM Interconnection, L.L.C. ("Operating Agreement") (which is the Network Operating Agreement under the Tariff and is incorporated herein by reference) and this Service Agreement, as they may be amended from time to time.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u> <u>(on behalf of Transmission Provider and Counterparty)</u>

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Network Customer

____

____

____

IN WITNESS WHEREOF, the Transmission Provider and the Network Customer have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:________________________ __________________________ ________
Name Title Date

Counterparty:

By: ______________________ _______________ ______________
Name Title Date

Network Customer

By:________________________ __________________________ ________
Name Title Date

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE
PURSUANT TO STATE REQUIRED RETAIL ACCESS PROGRAMS

1.0 Term of Service: The term of service under this Service Agreement shall be from _________ until terminated by mutual agreement of the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

2.0 Network Operating Agreement: In accordance with Section 29.1 of the Tariff, the Network Customer must be a member of PJM Interconnection, L.L.C. and a signatory to the Operating Agreement.

3.0 Network Load and Network Resources: The Network Customer shall be responsible for the Transmission Provider receiving the information pertaining to Network Load, Network Resources, and Behind The Meter Generation described in this section. Such information shall be provided in accordance with procedures established by the Transmission Provider. With respect to service requests under this umbrella Service Agreement, the Transmission Provider will deem the provision of the information specified in this section as complying with the application requirements set forth in Section 29.2 of the Tariff.

3.1 Network Load: For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company ("EDC") delivering to the Network Customer's load to provide directly to the Transmission Provider, on a daily basis, the Network Customer's peak load (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM), by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff. The peak load shall be expressed in terms of tenths of a megawatt and shall include all losses within the PJM Region, including other transmission losses, and distribution losses. Unless a more specific bus distribution is available, the EDC may provide a bus distribution for the Network Customer's peak load proportional to the bus distribution for all of the load in the Zone. The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement. For Non-Zone Network Load, the Network Customer shall provide to the Transmission Provider, on a daily basis, the Network Customer's peak load, by interconnection at the border of the PJM Region, coincident with the annual peak load of such area as determined under Section 34.1 of the Tariff. The peak load for such Non-Zone Network Load shall be expressed in terms of tenths of a megawatt and shall not include losses within the PJM Region. Unless a more specific bus distribution is identified and node definition requested, a service request shall be granted upon submission of the information set forth in this Section 3.1 without any further confirmation procedures. If a Network Customer under this Service Agreement, prior to the commencement of service or at any time after the commencement of service, identifies a more specific bus distribution and requests a node definition for all or part of its Network Load that is served under state required retail access programs, the Network Customer shall notify both the Transmission Provider and the electric distribution company pursuant to the notification procedure and schedule set forth in the PJM manuals. The Transmission Provider, exercising its independent judgment and expertise, shall have the authority to resolve any difference of opinion that may arise between the Network Customer and the electic distribution company as to the applicable bus distribution or node definition. If confirmed, the more specific bus distribution will not be used for billing and settlement purposes, however, until the notification procedure set forth in the PJM manuals is completed, and in no event until June 1, to correspond with the commencement of the annual planning period.

3.2 Network Resources: The Network Customer, as necessary, shall designate from time to time its Network Resources. In the event the Network Resource to be designated is Behind The Meter Generation, the designation must be made before the commencement of a Planning Period as that term is defined in the Operating Agreement and will remain in effect for the entire Planning Period. Such Network Resources must be acceptable to the Transmission Provider as Network Resources in accordance with the Tariff and the Operating Agreement. Designations of resources that have not previously been accepted as Network Resources of any Network Customer or Transmission Customer shall include the information set forth in Section 29.2(v) of the Tariff. Changes in the designation of Network Resources will be treated as an application for modification of service. The Network Customer shall confirm the acceptance of a Network Resource within 15 days of the completion of a System Impact Study or 30 days after completion of a Facilities Study, as is applicable. The Transmission Provider will maintain a current list of Network Resources, which shall be updated from time to time.

3.3 Hourly Load: The Network Customer and/or the EDCs delivering to the Network Customer's load shall provide to the Transmission Provider, on a daily basis, hourly loads and an associated bus distribution for the Network Load. For Network Load within the PJM Region, hourly loads required under this Section shall include all losses within such area, including transmission losses, and distribution losses. The Network Customer shall notify the Transmission Provider whether the Network Customer or the EDC will submit the hourly loads. The submitted load values will include losses and shall be reduced using the applicable loss factor determined by the Transmission Provider whenever a billing determination is calculated under the Tariff without losses.

3.4 Energy Schedules: The Network Customer shall schedule energy for its hourly loads in accordance with the Appendix to Attachment K of the Tariff.

3.5 Interruptible Loads: The Network Customer shall inform or shall arrange for each EDC delivering to Network Customer's load to inform Transmission Provider about the amount and location of any interruptible loads included in the Network Load. This information shall include the summer and winter peak load for each interruptible load (had such load not been interruptible), that portion of each interruptible load subject to interruption, the conditions under which an interruption can be implemented, and any limitations on the duration and frequency of interruptions.

3.6 Procedures for Load Determination: The procedures by which an EDC will determine the peak and hourly loads reported to the Transmission Provider under Sections 3.1 and 3.3 may be set forth in a separate schedule to the Tariff for each EDC.

3.7 Behind The Meter Generation: For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes.

4.0 Energy Imbalance Service: The Network Customer will receive Energy Imbalance Service from the Transmission Provider in accordance with Schedule 4 of the Tariff. Energy Imbalance Service is considered to be PJM Interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of the Tariff.

5.0 Reconciliation Billing: For Network Load within the PJM Region, to the extent required, the Transmission Provider will reconcile the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage, and provide corresponding charges and credits to Network Customer. Such reconciliation, if required, shall be made at the same rates as Energy Imbalance Service.

6.0 Designation of party subject to reciprocal service obligation: The Network Customer shall comply with Section 6 of the Tariff.

7.0 Name(s) of any Intervening Systems providing transmission service: To the extent any Network Resources are located outside the PJM Region, the list of Network Resources maintained by the Transmission Provider referenced in Section 3.2 of these specifications, shall identify any intervening systems needed to deliver those Network Resources to the Network Customer's retail load.

8.0 Charges: Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Embedded Cost Transmission Charge: The embedded cost transmission charge shall be determined in accordance with the formula set forth in Section 34 of the Tariff.

8.2 System Impact and Facilities Study Charges: To the extent Network Resources are located outside, or a new resource is added to, the PJM Region, a System Impact Study and/or Facilities Study Agreement and related charges may be required pursuant to Section 32 of the Tariff.

8.3 Direct Assignment Facilities Charge: To the extent that facilities or portions of facilities must be constructed by a Transmission Owner for the sole use or benefit of the Network Customer to accommodate the service requested by the Network Customer, the Network Customer shall be responsible for the cost of such Direct Assignment Facilities, and the charges for such facilities shall be specified at the time that the Transmission Provider determines the facilities that are needed to provide the requested service.

8.4 Ancillary Services Charge: In addition to Energy Imbalance Service, Transmission Provider shall bill the Network Customer for ancillary services in accordance with Schedules 1, 1-A, 2, 3, 5, 6, and 9 of the Tariff. To the extent required, the ancillary services charges shall also be reconciled based on any differences between the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage.

8.5 Other Supporting Facilities Charge: None.

8.6 **[Reserved]**

8.7 Other Charges: Transmission Provider shall charge Network Customer any and all other charges set forth in the Tariff applicable to providing Network Integration Service.

9.0 Designated Agent: To the extent that a Designated Agent for one or more Network Customers provides to the Transmission Provider any of the information required by these Specifications, it shall provide the information separately for each Network Customer.

CERTIFICATION

I, ________________________, certify that I am a duly authorized officer of

_________________________________ (Network Customer) and that

_________________________________ (Network Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Name)

Subscribed and sworn before me this ____ day of _________, _________.

____
(Notary Public)

My Commission expires:________________________

4. Offset of Credits and Debits to a Transmission User.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both amounts credited to a Transmission User in accordance with Section A(2) of this Attachment and amounts debited to a Transmission User in accordance with Section A(3) of this Attachment, and PJMSettlement shall exclude the Transmission User's transactions on the PJM Interchange Energy Market, in issuing a statement, invoice, or payment for the net amount owed to or by that Transmission User for Transmission Congestion Charges for any period.

Offset of Transmission Congestion Charges and Transmission Congestion Credits.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.

D. Transmission Service Components.

Transmission Congestion Charges and Transmission Congestion Credits, Ancillary Services charges and credits, Transmission Loss Charges, and allocations of Financial Transmission Rights auction revenues to a Transmission User are components of transmission service charges under Parts II and III of the Tariff and shall not give rise to separate transactions with PJMSettlement regarding the purchase or sale of electric energy.

1.1 Introduction.

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

1.5 Market Sellers.

1.5.1 Qualification.

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

1.5.2 Withdrawal.

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

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

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete the Economic Load Response 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.

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 appropriate electric distribution company or Load Serving Entity 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, and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. An 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity 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, and, if permitted, confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. If the 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, electric distribution company or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program 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 section 1.5A, including section 1.5A.3.

1.5A.4 Metering.

The Curtailment Service Provider is responsible to ensure that the Economic Load Response Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Economic Load Response Participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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 [Reserved for Future Use]

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 customer or its Curtailment Service Provider or Load Serving Entity 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"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

(a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-Ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-Ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection's filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-Ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-Ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-Ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants may participate in the Day-ahead and Real-time Energy Markets as dispatchable or self-scheduled resources, provided that Demand Resources that are self-scheduled pursuant to Section 1.5A.9(a) shall not be dispatched by the Office of the Interconnection pursuant to this section.

(a) Self-scheduled Demand Resources shall be subject to the following requirements:

i. An Economic Load Response Participant self-scheduling a Demand Resource shall notify the Office of the Interconnection no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event;

ii. Economic Load Response Participants may self-schedule a Demand Resource intra-hour;

iii. A Notification pursuant to this section may be withdrawn or adjusted downward during the relevant event hour, but not after the even hour;

iv. A Notification submitted pursuant to this section shall include the start and stop times of the event and the amount of the demand reduction;

v. The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the Economic Load Response Participant has provided a Notification.

1.5A.10 Economic Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 500 kW of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. If all End-Use Customers in an aggregation are not subject to the same generation and transmission charges, the generation and transmission charge for the aggregation shall be the load weighted average of the generation and transmission charges for all End-Use Customers in the aggregation. The Economic Load Response Participant shall provide the load weighted average, the calculation of the load weighted average, and the supporting data to the Load Serving Entity and PJM. For the purposes of this section, the applicable generation and transmission charges are the charges an End-Use Customer would have otherwise paid the Load Serving Entity absent the demand reduction;

v. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.4 and 3.3A.5;

vi. 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 99 kW 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 499 kW of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vii. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource except for the 100 kW minimum load reduction requirement for energy or the 500 kW minimum load reduction requirement for Ancillary Services; and

viii. An End-Use Customer’s participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM’s Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

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

1.6.2 Scope of Services.

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

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, ~~rendering bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants,~~ maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the ~~Office of the Interconnection~~Operating Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

vi) ~~Enter into~~Administer (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable

Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

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

1.6.3 Records and Reports.

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

1.6.4 PJM Manuals.

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

1.6A PJMSettlement

1.6A.1 Scope of Services

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (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 active load management, interruption of load, 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.

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

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses 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 eSchedules and Enhanced Energy Scheduler 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. ~~Neither t~~The LLC, PJMSettlement, ~~nor~~ 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 ~~the LLC~~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 eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy 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 eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. ~~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 ~~the Office of the Interconnection~~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 dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

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

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council 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 section 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 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 Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

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

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

1.7.18 Regulation.

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

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

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned.

(d) A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. 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

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

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

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

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

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

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

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to ~~the LLC~~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 eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets 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 eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

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

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 transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified 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.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

> i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;
>
> ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and
>
> iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each

other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, *this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals,* as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.5 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.5 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. 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).

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

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.5 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-Scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

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

1.10.4 Capacity Resources.

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

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

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load bus or busses 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 or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or busses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(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. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the

Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Regulation, Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section

1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed

Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues 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 Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the

Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_{t} = \left(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) \Big/ \left(\mathbf{UDSLAtime}_{t-1}\right)$$

$$\mathbf{RL\_Desired}_{t} = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_{t} * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated *balancing Operating Reserve* charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP *at the resource's bus does not meet or exceed* the *applicable* offer of the resource for at least four-5-minute intervals during one or more discrete *clock* hours *during each* period *the resource operated and produced MWs* during the relevant Operating Day. *If a resource operated* *and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.*

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each

Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the

Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (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 Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) ~~The Office of the Interconnection~~PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, ~~the Office of the Interconnection~~PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement ~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule, for demand reductions measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent highest load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. For the purposes of calculating the CBL for weekdays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. NERC holidays;

2. Event day(s), as defined in subsection (a)(i)(3) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual

threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

3. Weekdays the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection;

4. Any weekday the event period usage is less than 25% of the average event period usage for the five days.

iii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. For the purposes of calculating the CBL for Saturdays or Sundays/NERC holidays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45 day period):

1. Event day(s), as defined in subsection (b)(i)(1) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

2. Saturday or Sundays/NERC holidays where the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection.

iii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant, Load Serving Entity, electric distribution company, and/or the Office of the Interconnection ("Interested Parties") may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. Any proposal made pursuant to this section shall be provided to all other Interested Parties.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is received by all Interested Parties. If all Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon all Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.4 and 3.3A.5.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used soley to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Weather-Sensitive and Symmetric Additive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or "WSA") or Symmetric Additive Adjustment for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment and Symmetric Additive Adjustment shall be calculated using the following applicable formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer's on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index ("THI") on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

The regression analysis will produce a slope (m), expressing in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer's load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

$$WSA = [(m \times THIEVENT\ DAY) + b]/[(m \times THICBL\ DAYS) + b]$$

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer's location may be used if it can be shown that the temperature at the end-use customer's location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.

- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer's historical, seasonal, on-peak non-coincident peak load.

Symmetric Additive Adjustment

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by PJMSettlement ~~the Office of the Interconnection~~ the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) In cases where the demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(d) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer's zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant's zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, ~~the Office of the Interconnection~~ PJMSettlement shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer's demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price

less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(d) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

3.3A.6 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.4 and 3.3A.5 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market.

(b) Demand reductions that do not meet the requirements of Section 3.3A.6(a) shall not be eligible for settlement pursuant to Sections 3.3A.4 and 3.3A.5. Examples of settlements prohibited pursuant to this Section 3.3A.6(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint, provided that, the foregoing notwithstanding, settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.7 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted. PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. An Economic Load Response Participant's daily settlement will be denied by PJM based on the following criteria:

1) Submission of settlement for self schedule energy in the Real-time Energy Market where only some of the self scheduled hours have been included in the daily settlement submission; or

2) Daily settlement with an estimated value less than Five U.S. Dollars ($5.00); or

3) Daily settlement has a significant number of uneconomic hours *where the Locational Marginal Price is less than or equal to the generation plus the transmission portion of an end-use customer's retail rate or price*.

vi. The electric distribution company and the Load Serving Entity may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, retail rate, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.7. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement ~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or busses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

PJMSettlement on behalf of PJM ~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy market in the Day-ahead Energy Market at the Day-ahead Congestion prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by ~~the Office of the Interconnection~~PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule. ~~The Office of the Interconnection~~PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt busses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt busses is greater than the difference in Locational Marginal Prices between such delivery and receipt busses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a~~A~~ Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC’s rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to ~~the LLC~~PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of the busses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial

Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the ~~Members (or the Office of the Interconnection on behalf of the Members)~~ LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owner with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.

5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by PJMSettlement ~~the Office of Interconnection~~ in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to section 5.2.2(e) and the award of Financial Transmission Rights pursuant to section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction.

An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly, Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 PM (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual FTR auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term FTR auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term FTR auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term FTR auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of three rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 3 months after the first round, and the third round shall be conducted approximately 3 months after the second round. In each round 1/3 of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three business days ending at 5:00 p.m. on the last day. PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five business days after the close of the bidding period for each round. If the Office of the Interconnection discovers an error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of prices for that auction. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction.

Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

(i) The periods covered by long-term Financial Transmission Rights auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.

(ii) On-Peak, off-peak and 24-hour Financial Transmission Rights obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights Auction. Eligible receipt and delivery points in long-term Financial Transmission Rights Auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Financial Transmission Rights auctions conducted to liquidate a defaulting Member's Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in Section 7.3.9 herein and in accordance with standards and procedures set forth in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Rights sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offeror or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period,

market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.5of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any

offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.3.9 Liquidation of Financial Transmission Rights in the Event of Member Default.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the PJM Operating Agreement or PJM Tariff, the Office of the Interconnection shall, as soon as practicable after such default is declared, initiate the following procedures to close out and liquidate the Financial Transmission Rights of a Member:

a) The Office of the Interconnection shall close out the defaulting Member's positions as of the date of its default, by unilaterally accelerating and terminating all forward Financial Transmission Rights positions.

b) The Office of the Interconnection shall post on its website all salient information relating to the closed out portfolio of Financial Transmission Rights.

c) All current planning period Financial Transmission Right positions within the defaulting Members' Financial Transmission Right portfolio will be offered for sale in the next available monthly balance of planning period Financial Transmission Rights auction at an offer price designed to maximize the likelihood of liquidation of those positions.

d) Financial Transmission Rights positions that do not settle until the next or subsequent planning period will be offered into the next available Financial Transmission Rights auction (taking into account timing constraints and the need for an orderly liquidation) where, based on the Office of Interconnection's commercially reasonable expectation, such positions would be expected to clear. In the event that the next scheduled Financial Transmission Rights

auction is more than two (2) months subsequent to the date that the Office of the Interconnection declares a Member in default, a specially scheduled Financial Transmission Rights auction may be conducted by the Office of the Interconnection. The entire portfolio of the defaulting Member's Financial Transmission Rights will be offered for sale at an offer price designed to maximize the likelihood of liquidation of those positions.

e) The Financial Transmission Right positions comprising the defaulting Member's portfolio that are liquidated in a Financial Transmission Rights auction should avoid setting the price in the auction at the bid prices with which they were initially submitted. In the event that any of the closed out Financial Transmission Rights would set price based on the auction's preliminary solution, then only one-half of each Financial Transmission Rights position will be offered for sale and the auction will be re-executed. In the event that any Financial Transmission Rights position that has been closed out once again sets price, then all Financial Transmission Rights scheduled to be liquidated will be removed from the affected auction and the auction will be re-executed excluding the closed out Financial Transmission Right positions. Financial Transmission Right positions that are not liquidated will then be offered in the next available auction or specially scheduled auction, as appropriate.

f) The liquidation of the defaulting Members' Financial Transmission Rights portfolio pursuant to the foregoing procedures shall result in a final liquidated settlement amount. The final liquidated settlement amount will be included in calculating a Default Allocation Assessment as described in Section 15.1.2A(I) of the PJM Operating Agreement. If the Office of the Interconnection is unable to close out and liquidate a Financial Transmission Rights position under the foregoing procedures, the close out shall be deemed void and the defaulting Member shall remain liable for the full final value of its default, such full final value being realized at the normal time for performance of the Financial Transmission Rights position.

In all other respects, Financial Transmission Rights terminated pursuant to this section shall be liquidated pursuant to the appropriate provisions and procedures set forth in the PJM Manuals.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal

to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone.

Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f)

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points.

A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of the stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service Request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service Request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to ~~the LLC~~PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of Residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligations in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, ~~the Office of the Interconnection~~PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

PJM EMERGENCY LOAD RESPONSE PROGRAM

Emergency Load Response Program

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. As used in the Emergency Load Response Program, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program:

- Full Program Option

  Participants in the Full Program Option receive an energy payment for load reductions during an emergency event pursuant to the Reliability Assurance Agreement, as applicable.

- Energy Only Option

  Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

Participant Qualifications

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Members or Special Members may participate in the Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response provisions herein, including, but not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C***. However, for special members the $5,000 annual membership fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

Special Members are limited to be PJM market sellers;
Voting privileges and sector designation are waived;
Thirty day notice for waiting period is waived;
Requirement for 24/7 control center coverage is waived;
No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

Be capable of reducing at least 100 kW of load
Be capable of receiving PJM notification to participate during emergency conditions.

Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Participant must meter reductions in demand by using either of the following two methods:

a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or

b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

a) Metering equipment used for retail electric service;

b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or

c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com)for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals.Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, Participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than eleven business days prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, given that the electric distribution company and load serving entity must comply with a ten business day review period. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection with ten or fewer business days remaining prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, then the registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration prior to the registration deadline. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection. The following general steps will be followed:

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

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An 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) an end-use customer's participation in PJM's Emergency Load Response Program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after June 1 of the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

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

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

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the 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 Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer's participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements, the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency 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.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program, or notifies the requesting participant and appropriate Load Serving Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance

with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Emergency Load Response Registrations in Effect as of August 28, 2009

All existing Emergency Load Response Participants' registrations submitted to PJM prior to 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")) for Load Management participation in the 2009/2010 Delivery Year will remain effective for that Delivery Year.

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price of a Full Program Option participant that reduces load may set the real time Locational Marginal Price ("LMP") provided that the participant's load reductions are needed to meet demand in the PJM Region. The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the Energy Only Option participant's resource satisfies PJM's telemetry requirements.

Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for the hour prior to the event, as well as every hour during the event. These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option participants shall be the amount PJM dispatches up to the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Reporting

Actual load reductions of Energy Only Option emergency resources will be added back for the purpose of peak load calculations for capacity.

Actual load reductions of Full Program Option and Capacity Only resources that have been registered as Emergency Load Response resources and/or Economic Load Response resources, and which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity. Capacity Only resources are Full Program Option resources that do not receive an energy payment for load reductions during an emergency event. Actual load reductions used for the purpose of calculating peak load for capacity, however, shall not exceed the quantity of kW committed and registered as Full Program Option or Capacity Only resources.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.3 of PJM Emergency Load Response Program, 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 Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

Non-hourly metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response Program that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response Participant aggregations shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. Energy settlement will be based on each individual customer's load reductions pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and

v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

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

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

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

2.21 Demand Resource Factor

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

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Demand Resource.

2.23 EFORd

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

2.24 Energy Efficiency Resource

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

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

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

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 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.

2.28 Forecast Pool Requirement

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

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced

Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

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

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.37 Load Serving Entity (LSE)

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

2.38 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 Schedule 10.1 of the Reliability Assurance Agreement.

2.39 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.

2.40 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.

2.41 Locational Reliability Charge

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

2.41A 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.

2.41B Locational UCAP Seller

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

2.41C 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 section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.42 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, as defined in Section 5.

2.43 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.

2.43A 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.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity 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 ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be dispatched independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be dispatched for such block.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

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

2.50 Planned External Generation Capacity Resource

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

2.50A Planned Generation Capacity Resource

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

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

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

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the

Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 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.

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 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. ~~An LSE may submit a~~ A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource~~, but such Sell Offer~~ 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~~solely as such term is used in this Attachment~~.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, 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.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (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.

2.66 Third Incremental Auction

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

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B 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.

2.69C 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.

2.70 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 Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining ILR Forecasts for Delivery Years through May 31, 2012;

d) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

e) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

f) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

g) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

h) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

i) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment, Attachment M, Attachment M - Appendix, the Operating Agreement, and the Reliability Assurance Agreement, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, or Reliability Backstop Auction shall be deemed confidential information for purposes of Section 18.17 of the Operating Agreement, Attachment M and Attachment M - Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, 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 Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to ~~the LLC~~PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its eRPM tools. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, 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 Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions as defined in, and pursuant to the rules set forth in, section 5.3A of this Attachment DD, which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such 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 Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its eRPM tools. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

5.1 Introduction

In accordance with the Reliability Assurance Agreement, each Load Serving Entity is obligated to pay a Locational Reliability Charge for each Zone in which it serves load based on the Daily Unforced Capacity Obligation of its loads in such Zone. An LSE may offset the Locational Reliability charge for a Delivery Year, in whole or in part, by: (a) Self-Supply of Capacity Resources in the Base Residual Auction or an Incremental Auction; (b) offering and clearing Capacity Resources in the Base Residual Auction or an Incremental Auction (but only to the extent of the additional resources committed to meet Unforced Capacity Obligations through such Incremental Auction); (c) obtaining certification of load reduction capability as ILR three months prior to the start of the Delivery Year (to the extent permitted hereunder); (d) receiving payments from Capacity Transfer Rights; or (e) offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals~~,~~. ~~except that~~ ~~the~~ The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is ~~to~~ committing the resource regardless of clearing price or with a price bid. Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the ~~Base Residual~~Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply ~~subject to an offer price~~ (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.3 Commitment of Contractually Purchased Capacity Resources

A Load Serving Entity that has purchased the right to the capacity output of a generation resource and desires to commit such right as a Capacity Resource for a Delivery Year shall be considered a Capacity Market Seller. Such an LSE must submit a Sell Offer in the Base Residual Auction for such Delivery Year, in accordance with the procedure and time schedule set forth in the PJM Manuals. In such Sell Offer, the Capacity Resource offered by the LSE may be submitted as Self-Supply or with an offer price. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction for the purposes set forth in section 2.34. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional

Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, and (2) the Locational Price Adder, if any in such LDA, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily UnforcedCapacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

a. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

b. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

c. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: 1) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or 2) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.

If the Sell Offer is submitted consistent with the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

(ii) in the subsequent two BRAs, if the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA. If the Resource does not clear, it shall be deemed resubmitted at the highest price per MW at which the Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and it shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer that is entitled to compensation for such first year pursuant to section 5.14(b) of this Attachment. The Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect such resubmission. In such case, the Resource submitted under this provision shall be paid for the entire committed quantity the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer Price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; and 3) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal (1) the sum, for all auctions previously conducted for such Delivery Year, of the Resource Clearing Price for each auction times the Unforced Capacity cleared for such auction (excluding any Unforced Capacity cleared as replacement capacity), divided by (2) the sum of the Unforced Capacity cleared in all such auctions (excluding any Unforced Capacity cleared as replacement capacity), plus an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based, real levelized (year one) Cost of New Entry, net of energy and ancillary service revenues. Other than the levelization approach, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. Until changed, the Net Asset Class Cost of New Entry for a combustion turbine generator shall be \$ 96,485MW-year, and the Net Asset Class Cost of New Entry for a combined cycle generator shall be \$ 117,035/MW-year. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) base load resources, such as nuclear, coal and Integrated Gasification Combined Cycle, that require a period for development greater than three years; (ii) any facility associated with the production of hydroelectric power; (iii) any upgrade or addition to an existing Generation Capacity Resource; or (iv) any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

(2) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, in any LDA for which a separate VRR Curve has been established, and that meets each of the following criteria, shall be subject to the provisions of subsection (3) hereof,

unless the Capacity Market Seller obtains a determination from FERC prior to such Base Residual Auction that such Sell Offer is consistent with the real levelized (year one) competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets):

i. Sell Offer affects the Clearing Price;

ii. Sell Offer is less than 80 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as stated in subsection (h)(1) above; and

iii. The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts. A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply. An "actual retail load obligation" shall mean the LSE's combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement. A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the BRA, under contract for the Delivery Year.

(3) The Office of the Interconnection shall perform a sensitivity analysis on any Base Residual Auction that included Sell Offers meeting the criteria of Section 5.14(h)(2), for which the Capacity Market Seller has not obtained a prior favorable determination from FERC as described in subsection (2) hereof. Such analysis shall re-calculate the clearing price for the Base Residual Auction employing in place of each actual Sell Offer meeting the criteria a substitute Sell Offer equal to 90 percent of the applicable estimated cost determined in accordance with Section 5.14(h)(1) above, or, if there is no applicable estimated cost, equal to 80 percent of the then-applicable Net CONE. If the resulting difference in price between the new clearing price and the initial clearing price differs by an amount greater than the greater of 20 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 15,000 megawatts; or the greater of 25 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 5,000 and less than 15,000 megawatts; or the greater of 30 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement of less than 5,000 megawatts; then the Office of the interconnection shall discard the results of the Base Residual Auction and determine a replacement clearing price and the identity of the accepted Capacity Resources using the procedure set forth in section 5.14(h)(4) below.

(4) Including all of the Sell Offers in a single Base Residual Auction that meet the criteria of 5.14(h)(3) above, PJM shall first calculate the replacement clearing price and the

total quantity of Capacity Resources needed for the LDA. PJM shall then accept Sell Offers to provide Capacity Resources in accordance with the following priority and criteria for allocation: (i) first, all Sell Offers in their entirety designated as self-supply committed regardless of price; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price, subject to the optimization principles set forth in Section 5.14.

(5) Notwithstanding the foregoing, this provision shall terminate when there exists a positive net demand for new resources, as defined in Section 5.10(a)(iv)(B) of this Attachment, calculated over a period of consecutive Delivery Years beginning with the first Delivery Year for which this Attachment is effective and concluding with the last Delivery Year preceding such calculation, in an area comprised of the Unconstrained LDA Group (as defined in section 6.3) in existence during such first Delivery Year. Notwithstanding the foregoing, the Office of the Interconnection shall reinstate the provisions of this section, solely under conditions in which a constrained LDA has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.

(i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained

LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of installed capacity, applicable to price-quantity offers within the Base Offer Segment for an existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the

Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from a Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in the Base Residual Auction or Incremental Auction for adjustment of committed capacity for the first Delivery Year for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources shall be treated as Existing Generation Capacity Resources in the auctions for any subsequent Delivery Year; provided, however, that such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all Unforced Capacity of all existing Generation Capacity Resources located in the PJM Region shall be offered (which may include submission as Self-Supply) in the Base Residual Auction for each Delivery Year, where Unforced Capacity is determined using an EFORd less than or equal to the greater of (i) the annual average EFORd for the five consecutive years ending on the September 30 that last precedes the submission of such offers or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the EFORd applicable to each resource. The Generation Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed EFORd, and attempt to reach agreement with the Market Monitoring Unit on the level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.C of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of the EFORd, the Office of the Interconnection shall make its own determination of the level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) Existing generation resources in the PJM Region capable of qualifying as a Generation Capacity Resource may not avoid the rule in subsection (a) by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource, excepting only generation resources that, as shown by appropriate documentation: (i) are reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) have a financially and physically firm commitment to an external sale of its capacity, or (iii) were interconnected to the Transmission System as Energy Resources and not subsequently converted to a Capacity Resource. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff;

B. Significant physical operational restrictions that cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff; or,

C. The Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource.

(h) Any existing generation resource located in the PJM Region that is not offered into the Base Residual Auction for a Delivery Year, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

(i) To avoid application of subsection (j), any existing Generation Capacity Resource located in the PJM Region that is offered into the Base Residual Auction for a Delivery Year, but that does not clear in such auction, shall be offered in the First, Second, and Third Incremental Auctions (and any Conditional Incremental Auction) for such Delivery Year, unless such Generation Capacity Resource, as shown by appropriate documentation, (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

(j) Any existing Generation Capacity Resource located in the PJM Region that is offered into the Base Residual Auction for a particular Delivery Year, does not clear in such auction, is not offered into the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, and does not meet any of the exceptions stated in subsection (g): (i) may not participate in any subsequent auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year; (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year, and (iv) may be subject to further action by the Market Monitoring Unit under Attachment M and Attachment M - Appendix.

(k) In addition to the remedies set forth in subsections (g), (h), (i), and (j), if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources into an auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the

Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource

Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Maximum Avoidable Cost Rates by Technology Class

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate. The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(c) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-

Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

  - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

  - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

  - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

  - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

  - **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

  - **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 16 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as “at-risk” at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

16. RELIABILITY BACKSTOP

16.1. Purpose

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by: (a) lack of sufficient capacity committed through the Reliability Pricing Model Auctions; or (b) near-term transmission deliverability violations identified after the Base Residual Auction is conducted. These backstop mechanisms are intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The backstop mechanisms are based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources through Self-Supply or the Reliability Pricing Model Auctions.

16.2 Investigation of Capacity Shortfall

If the total Unforced Capacity of Capacity Resources committed for a Delivery Year following the Base Residual Auction equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection shall investigate the cause for the shortage, and recommend corrective action, including, without limitation, adjusting the Cost of New Entry to the extent determined necessary by such investigation, or addressing other barriers to entry identified by such investigation. No Reliability Backstop Auction will be conducted to address such a shortfall unless it occurs in the Base Residual Auctions for three consecutive Delivery Years.

16.3 Triggering Conditions

a) Either of the following two conditions will trigger reliability backstop measures provided in this section, as described below:

i) If the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years, equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection will declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

ii) If the total Unforced Capacity of all Base Load Generation Resources committed in a Base Residual Auction for a Delivery Year is less than the forecasted minimum hourly load calculated by the Office of the Interconnection for such Delivery Year, the Office of the Interconnection will investigate the cause of shortfall. If such a shortfall occurs in the Base Residual Auctions for three consecutive Delivery Years, the Office of the Interconnection shall declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

b) In addition to the foregoing events that trigger reliability backstop measures, if a near-term, i.e., later in time than the conduct of the Base Residual Auction for a Delivery Year, transmission criteria violation caused by an announced generation resource deactivation is identified by the regional transmission reliability planning analysis performed by the Office of the Interconnection in accordance with Part V of this Tariff, the Office of the Interconnection will identify the necessary transmission upgrade. In accordance with such rules, such generation resource may remain in service until the transmission upgrade is installed. No Reliability Backstop Auction will be conducted.

16.4. Reliability Backstop Auction

a) Scope of Auction

The Office of the Interconnection shall conduct each Reliability Backstop Auction to commit additional Generation Capacity Resources, or in the case of an auction triggered by section 16.3(a)(ii), additional Base Load Generation Resources to the PJM Region to resolve the system-wide reliability criteria violation that triggered the need for such auction. Capacity Resources committed in a Reliability Backstop Auction for a Delivery Year shall not include any Planned Generation Capacity Resources previously committed in the Base Residual Auction for such Delivery Year. The Reliability Backstop Auction shall obtain commitments of additional Generation Capacity Resources (or, as applicable, additional Base Load Generation Resources) for a term of up to fifteen (15) Delivery Years. If a Reliability Backstop Auction is required, the offer period for such auction shall commence, subject to FERC approval as specified above, no later than four months after the Base Residual Auction in which the third consecutive Capacity Resource shortfall occurs. Upon verification and notification by the PJM Board of Managers that a Reliability Backstop Auction is required, the Office of the Interconnection shall post notification that a Reliability Backstop Auction is to be held. Upon such notification, the offer period shall commence, and shall remain open for six (6) months. PJMSettlement shall be the Counterparty to the capacity transaction resulting from committed Capacity Resources clearing the Reliability Backstop Auction.

b) Sell Offers

Each Sell Offer shall specify the following information, as further specified in the PJM Manuals:

- the minimum price in $/MW-day required by the Capacity Market Seller to provide additional Unforced Capacity from a Generation Capacity Resource (or from a Base Load Generation Resource, in the case of an auction triggered by section 16.3(a)(ii));

- the megawatts of Unforced Capacity to be provided by such resource;

- the specific location of the proposed plant;

- all information required from a Generation Interconnection Customer by Part IV of this Tariff and the PJM Manuals;

- general plant technical specifications, as specified in the PJM Manuals;

- the term of cost recovery ("Backstop Period") requested, not to exceed 15 years; and

- the first full Delivery Year for which such resource shall be available, which shall also be the first year of the Backstop Period.

Each Generation Capacity Resource (or Base Load Generation Resource) accepted in a Reliability Backstop Auction shall comply with the procedures for new generation interconnection in Part IV of this Tariff, and each such resource shall be responsible for satisfying all capability and deliverability requirements for Capacity Resources, pursuant to the Reliability Assurance Agreement.

c) Submission of Sell Offers

The Sell Offer period shall begin at 00:01 Eastern Prevailing Time on the date specified by the Office of the Interconnection in the notification posting and shall end at 23:59 Eastern Prevailing Time six calendar months after such date. Sell offers shall be submitted during such period in writing to the Office of the Interconnection, and shall conform to the submission procedures as specified in the PJM Manuals. The Office of the Interconnection shall confirm in writing the receipt of each Sell Offer, within two weeks after receipt of each such offer.

d) Posting of Information by the Office of the Interconnection

Upon notification by the PJM Board of Managers that a Reliability Backstop Auction will be conducted, the Office of the Interconnection shall post the following information:

- System condition that necessitates a Reliability Backstop Auction;

- Megawatt quantity of Unforced Capacity required from additional Generation Capacity Resources, or from additional Base Load Generation Resources;

- Date by which the resources must be capable of delivering Unforced Capacity;

- Any other required specifications for the additional Unforced Capacity sought through such auction.

e) Conduct of the Reliability Backstop Auction

i) Auction Clearing Procedure

The Reliability Backstop Auction shall select the Sell Offer or combination of Sell Offers that that satisfies the requirements posted by the Office of the Interconnection at the lowest offer price(s). If more than one Sell Offer must be selected to satisfy the specified requirements, the Sell Offers shall be selected in rank order from lowest offer price to highest offer price until the requirement is satisfied. In the event two or more Sell Offers specify the same offer price, and fewer than all of such offers are needed to satisfy the specified requirements, the Office of the Interconnection shall select the Sell Offer(s) proposing Generation Capacity Resource(s), or, as applicable, Base Load Generation Resource(s) that will best satisfy overall reliability requirements for the PJM Region, as determined by the Office of the Interconnection using transmission reliability analysis.

ii) Market Settlement

Pursuant to the agreement specified below, each Capacity Market Seller submitting a Sell Offer that is accepted in a Reliability Backstop Auction shall be paid by PJMSettlement the offer price in such Sell Offer for each MW-day in the Backstop Period, less any payments the Capacity Market Seller is entitled to receive pursuant to section 5 of this Attachment as a result of Sell Offers submitted with respect to such Generation Capacity Resource in any Base Residual Auction or Incremental Auction, including, without limitation, payments of Capacity Resource Clearing Prices (including for Self-Supply) and Resource Make-Whole Payments; and less any payments the Capacity Market Seller is entitled to receive for energy or ancillary services pursuant to Schedule 1 of the Operating Agreement with respect to services provided by such resource, net of the Variable Operations and Maintenance costs of such resource, as determined in accordance with the PJM Manuals.

PJM shall recover the costs of any such payments to Capacity Market Sellers for such resources through a charge, in addition to the Locational Reliability Charge, assessed on all LSEs in the PJM Region, pro rata based on each such LSE's Daily Unforced Capacity Obligations in all LDAs in which such LSE serves load. PJMSettlement shall be the Counterparty to the LSE's obligation to pay, and payment of, such charges.

iii) Standard Contract Provisions

~~The Office of the Interconnection, on behalf of all LSEs in the PJM Region~~PJMSettlement, will enter into an agreement with each Capacity Market Seller that submitted an accepted Sell Offer in any Reliability Backstop Auction providing for the payments specified above. Such agreement shall include the provisions and address the standards set forth in Section 16.4(b), and shall include such other terms and conditions as are customary in the industry, as specified in the PJM Manuals.

f) FERC Approval

Any such agreement shall provide that it shall be filed with FERC as a rate schedule pursuant to section 205 of the Federal Power Act, and that the effectiveness of such agreement shall be conditioned on receipt of FERC acceptance or approval of such agreement.

16.5 Must Offer into Base Residual Auction

All Capacity Market Sellers submitting a Sell Offer that is selected in a Reliability Backstop Auction must offer all Unforced Capacity of the Generation Capacity Resource underlying such Sell Offer into the Base Residual Auctions conducted subsequent to the Reliability Backstop Auction for all Delivery Years in the Backstop Period. The Market Seller shall offer the

Unforced Capacity of such resources into each such auction at zero price, and shall receive the Capacity Resource Clearing Price as determined in each such auction.

16.6 Reliability Backstop Resource Deficiency Charges

(a) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that is not able to deliver in a Delivery Year all megawatts of Unforced Capacity specified in the selected Sell Offer, shall not receive any payments that such Capacity Market Seller otherwise would have been eligible to receive for such Delivery Year pursuant to the Reliability Backstop Auction.

(b) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that fails to deliver all megawatts of Unforced Capacity specified in the selected Sell Offer at any time during the Backstop Period specified in such Sell Offer must refund all payments received by such Market Seller pursuant to section 16.4(b).

PJM Operating Agreement Revisions

(Redlined Version)

Definitions C - D

1.6 Capacity Resource.

"Capacity Resource" have the meaning provided in the Reliability Assurance Agreement.

1.6A Consolidated Transmission Owners Agreement.

"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.

1.7 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 the applicable regional reliability council of NERC;

(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.

1.7.01 Control Zone.

"Control Zone" shall mean any of the ECAR Control Zone(s), MAAC Control Zone, or MAIN Control Zone(s), or the VACAR Control Zone.

1.7.01a Counterparty.

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

"Default Allocation Assessment" shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

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

1.7A [Reserved].

1.7B [Reserved].

Definitions O - P

1.27 Office of the Interconnection.

"Office of the Interconnection" shall mean the LLC. ~~the employees and agents of the LLC engaged in implementation of this Agreement and administration of the PJM Tariff, subject to the supervision and oversight of the PJM Board acting pursuant to this Agreement.~~

1.28 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 a Control Zone, as specified in the PJM Manuals.

1.29 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.

1.30 Other Supplier.

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillatry 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.

1.31 PJM Board.

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to this Agreement.

1.31A [Reserved].

1.32 PJM Control Area.

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

1.33 PJM Dispute Resolution Procedures.

"PJM Dispute Resolution Procedures" shall mean the procedures for the resolution of disputes set forth in Schedule 5 of this Agreement.

1.34 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 Schedule 1 to this Agreement.

1.35 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.

1.35.01 PJM Market Monitor.

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

1.35A PJM Region.

"PJM Region" shall mean the aggregate of the MAAC Control Zone, the PJM West Region, and VACAR Control Zone.

1.35B PJM South Region.

"PJM South Region" shall mean the VACAR Control Zone.

1.35C PJMSettlement.

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

1.36 PJM Tariff.

"PJM Tariff" shall mean the PJM Open Access Transmission Tariff providing transmission service within the PJM Region, including any schedules, appendices, or exhibits attached thereto, as in effect from time to time.

1.36A [Reserved.]

1.36B PJM West Region.

"PJM West Region" shall mean the aggregate of the ECAR Control Zone(s) and MAIN Control Zone(s).

1.37 Planning Period.

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

1.38 President.

"President" shall have the meaning specified in Section 9.2.

7.7 Duties and Responsibilities of the PJM Board.

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

i) As its primary responsibility, ensure that the President, the other officers of the LLC, and Office of the Interconnection perform the duties and responsibilities set forth in this Agreement, including but not limited to those set forth in Sections 9.2 through 9.4 and Section 10.4 in a manner consistent with (A) the safe and reliable operation of the PJM Region, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and (C) the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Region;

ii) Select the Officers of the LLC;

iii) Adopt budgets for the LLC;

iv) Approve the Regional Transmission Expansion Plan in accordance with the provisions of the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of this Agreement;

v) On its own initiative or at the request of a User Group as specified herein, submit to the Members Committee such proposed amendments to this Agreement or any Schedule hereto, or a proposed new Schedule, as it may deem appropriate;

vi) Petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings;

vii) Review for consistency with the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region any change to rate design or to non-rate terms and conditions proposed by Transmission Owners for filing under section 205 of the Federal Power Act;

viii) If and to the extent it shall deem appropriate, intervene in any proceeding at FERC initiated by the Members in accordance with Section 11.5(b), and participate in other state and federal regulatory proceedings relating to the interests of the LLC;

ix) Review, in accordance with Section 15.1.3, determinations of the Office of the Interconnection with respect to events of default;

x) Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to PJMSettlement and the Office of the Interconnection, including interest thereon, as to which a Member is in default;

xi) Establish reasonable sanctions for failure of a Member to comply with its obligations under this Agreement;

xii) Direct the Office of the Interconnection on behalf of the LLC and PJMSettlement to take appropriate legal or regulatory action against a Member (A) to recover any unpaid amounts due from the Member to the Office of the Interconnection under this Agreement and to make whole any Members subject to an assessment as a result of such unpaid amount, or (B) as may otherwise be necessary to enforce the obligations of this Agreement;

xiii) [Reserved.]

xiv) [Reserved.]

xv) Solicit the views of Members on, and commission from time to time as it shall deem appropriate independent reviews of, (a) the performance of the PJM Interchange Energy Market, (b) compliance by Market Participants with the rules and requirements of the PJM Interchange Energy Market, and (c) the performance of the Office of the Interconnection under performance criteria proposed by the Members Committee and approved by the PJM Board; and

xvi) Terminate a Member as may be appropriate under the terms of this Agreement.

11.6 Membership Requirements.

(a) To qualify as a Member, an entity shall:

i) Be a Transmission Owner a Generation Owner, an Other Supplier, an Electric Distributor, or an End-Use Customer; and

ii) Accept the obligations set forth in this Agreement.

(b) Certain Members that are Load Serving Entities are parties to the Reliability Assurance Agreement. Upon becoming a Member, any entity that is a Load Serving Entity in the PJM Region and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement

(c) An entity that wishes to become a party to this Agreement shall apply, in writing, to the President setting forth its request, its qualifications for membership, its agreement to supply data as specified in this Agreement, its agreement to pay all costs and expenses in accordance with Schedule 3, and providing all information specified pursuant to the Schedules to this Agreement for entities that wish to become Market Participants. Any such application that meets all applicable requirements shall be approved by the President within sixty (60) days.

(d) Nothing in this Section 11 is intended to remove, in any respect, the choice of participation by other utility companies or organizations in the operation of the PJM Region through inclusion in the System of a Member.

(e) An entity whose application is accepted by the President pursuant to Section 11.6(c) shall execute a supplement to this Agreement in substantially the form prescribed in Schedule 4, which supplement shall be countersigned by the President. The entity shall become a Member effective on the date the supplement is countersigned by the President.

(f) Entities whose applications contemplate expansion or rearrangement of the PJM Region may become Members promptly as described in Sections 11.6(c) and 11.6(e) above, but the integration of the applicant's system into all of the operation and accounting provisions of this Agreement and the Reliability Assurance Agreement, shall occur only after completion of all required installations and modifications of metering, communications, computer programming, and other necessary and appropriate facilities and procedures, as determined by the Office of the Interconnection. The Office of the Interconnection shall notify the other Members when such integration has occurred.

(g) Entities that become Members will be listed in Schedule 12 of this Agreement.

(h) In accordance with the MAAC Agreement, a Member serving load in the MAAC Control Zone shall be a member of MAAC and any other Member may be a member of MAAC.

(i) In accordance with this Agreement, Members agree that PJMSettlement shall be the Counterparty with respect to certain transactions under the PJM Tariff and this Agreement.

14B.1 Billing Procedure:

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

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

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

(c) Billing Statement. PJMSettlement, in its own name and as agent for ~~T~~the Office of the Interconnection, as applicable, shall provide Members and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Member's or other entity's activity during the billing month and amounts due, net of activity previously billed.

14B.2 Payments:

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

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

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

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

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

14B.3 Interest on Unpaid Balances:

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by PJMSettlement~~the LLC~~.

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

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

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

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

(i) A Member shall be entitled to payment from PJMSettlement during the settlement period if, and only if, during the settlement period there is no amount in default due and payable by that Member to PJMSettlement with respect to transactions for which PJMSettlement is a Counterparty and not paid or recovered and so long as an amount in default, or any part of it, remains owing to PJMSettlement, that Member will not request, demand or claim to be entitled to payment by PJMSettlement.

(ii) Subject to section 15, a defaulting Member shall be entitled to payment from PJMSettlement with respect to transactions for which PJMSettlement is the Counterparty, if, and only if, all amounts, liabilities and other obligations due, owing, incurred or payable by that defaulting Member to PJMSettlement or the LLC, whether those liabilities or obligations are actual or contingent, present or future, joint or several (including, without limitation, all interest (after as well as before judgment) and expenses) have been paid or recovered and until that time the defaulting Member will not request, demand or claim to be entitled to payment by PJMSettlement or the LLC.

(d) **Set-off.**

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

(ii) If in respect of any non-paying Member there is more than one amount in default, then any amount due and payable from PJMSettlement shall be set off against the amounts in default in the order in which they originally became due and payable.

(e) **Liability of PJMSettlement.**

(i) The liability of PJMSettlement to make payments during the settlement period shall be limited so that the aggregate of such payments does not exceed the aggregate amount of payments that has been paid to or recovered by PJMSettlement, from Members (including by way of realization of financial security) in respect of that settlement period.

(ii) Where in relation to any settlement period, the aggregate amount that PJMSettlement pays to Members with respect to transactions for which PJMSettlement is the Counterparty is less than the amount to which those Members, but for the operation of section 14B(e)(i), would have been entitled: if and to the extent that, after the required time during the settlement period, PJMSettlement or the LLC is paid and recovers (including collection of such amount through Default Allocation Assessments) amounts from any Member, PJMSettlement shall to the extent of such receipts make payments (to certain Members) in accordance with the provisions of section 15.2.1.

15.1 Failure to Meet Obligations.

15.1.1 Termination of Market Buyer Rights.

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

15.1.2 Termination of Market Seller Rights.

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

15.1.2A Close Out and Liquidation of Member Financial Transmission Rights

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

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

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

15.1.3 Payment of Bills.

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

15.1.4 Breach Notification and Remedy

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

15.1.5 Default Notification and Remedy

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

i) A defaulting Market Participant shall be precluded from buying or selling in the PJM Interchange Energy Market, the PJM Capacity Credit Market, or any other market operated by PJM until the default is remedied as set forth above;

ii) A defaulting Member shall not be entitled to participate in the activities of any committee or other body established by the Members Committee or the Office of the Interconnection; and

iii) A defaulting Member shall not be entitled to vote on the Members Committee or any other committee or other body established pursuant to this Agreement.

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

15.1.6 Reinstatement of Member Following Default and Remedy

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

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

a) Loss of stakeholder privileges, including voting privileges, for 12 months following such default; and

b) Loss of the allowance of unsecured credit for 12 months following such default

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

a) PJMSettlement shall close out and liquidate all of the terminated Member's current and forward positions in accordance with the provisions of this Agreement; and

b) A Member terminated in accordance with these provisions shall be precluded from seeking future membership under this Agreement;

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

a) that it has otherwise consistently complied with its obligations under this Agreement and the PJM Tariff; and

b) the failure to comply was not material; and

c) the failure to comply was due in large part to conditions that were not in the common course of business.

15.5 No Implied Waiver.

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

15.6 Limitation on Claims.

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

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

16.6 Gross Negligence or Willful Misconduct.

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

1.1 Introduction.

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

1.5 Market Sellers.

1.5.1 Qualification.

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

1.5.2 Withdrawal.

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

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

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete the Economic Load Response 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.

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 appropriate electric distribution company or Load Serving Entity 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, and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. An 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity 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, and, if permitted, confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. If the 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 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, electric distribution company or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program 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 Participants' registrations 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 section 1.5A, including section 1.5A.3.

1.5A.4 Metering.

The Curtailment Service Provider is responsible to ensure that the Economic Load Response Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Economic Load Response Participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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 [Reserved for Future Use]

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 customer or its Curtailment Service Provider or Load Serving Entity 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”). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.04 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.07 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

(a) A Batch Load Demand Resource may provide Sychronized Reserve or Day-ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection's filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Sychronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants may participate in the Day-ahead and Real-time Energy Markets as dispatchable or self-scheduled resources, provided that Demand Resources that are self-scheduled pursuant to Section 1.5A.9(a) shall not be dispatched by the Office of the Interconnection pursuant to this section.

(a) Self-scheduled Demand Resources shall be subject to the following requirements:

i. An Economic Load Response Participant self-scheduling a Demand Resource shall notify the Office of the Interconnection no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event;

ii. Economic Load Response Participants may self-schedule a Demand Resource intra-hour;

iii. A Notification pursuant to this section may be withdrawn or adjusted downward during the relevant event hour, but not after the event hour;

iv. A Notification submitted pursuant to this section shall include the start and stop times of the event and the amount of the demand reduction;

v. The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the Economic Load Response Participant has provided a Notification.

1.5A.10 Economic Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 500 kW of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. If all End-Use Customers in an aggregation are not subject to the same generation and transmission charges, the generation and transmission charge for the aggregation shall be the load weighted average of the generation and transmission charges for all End-Use Customers in the aggregation. The Economic Load Response Participant shall provide the load weighted average, the calculation of the load weighted average, and the supporting data to the Load Serving Entity and PJM. For the purposes of this section, the applicable generation and transmission charges are the charges an End-Use Customer would have otherwise paid the Load Serving Entity absent the demand reduction;

v. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.4 and 3.3A.5;

vi. 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 99 kW 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 499 kW of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vii. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource except for the 100 kW minimum load reduction requirement for energy or the 500 kW minimum load reduction requirement for Ancillary Services; and

viii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

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

1.6.2 Scope of Services.

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

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, ~~rendering bills to the Market Participants, receiving payments from and disbursing payments to the Market Participants,~~ maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the ~~Office of the Interconnection~~ Operating Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

vi) Administer~~Enter into~~ (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

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

1.6.3 Records and Reports.

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

1.6.4 PJM Manuals.

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

1.6A PJMSettlement

1.6A.1 Scope of Services

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (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 active load management, interruption of load, 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.

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

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

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

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler 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. ~~Neither~~ T~~t~~he LLC, PJMSettlement, and ~~nor~~ 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~~the LLC~~ 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 eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy 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 eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. ~~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 the extent that the buyer has made an indemnification payment to PJMSettlement~~the Office of the Interconnection~~ 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 dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

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

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or

(2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council 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 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 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 Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

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

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

1.7.18 Regulation.

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

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

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned.

(d) A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit’s Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator’s megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. 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.

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

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

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

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

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, 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 Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets 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 eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the

Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

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

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

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

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

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

Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

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 *M*arket. 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 transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified 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.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction, amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.5 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.5 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. 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).

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

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.5 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

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

1.10.4 Capacity Resources.

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

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

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load 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 or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or buses.

(b) An External Market Buyer’s hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member’s energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(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. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve *Obligation* from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulationmarket-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Regulation Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues 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 Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for

Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = (\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{UDSLAtime}_{t-1})$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time

3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated *balancing Operating Reserve* charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP *at the resource's bus does not meet or exceed* the *applicable* offer of the resource for at least four-5-minute intervals during one or more discrete *clock* hour*s during each* period *the resource operated and produced MWs* during the relevant Operating Day. *If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.*

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone, for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or

Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services 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 (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 Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement~~the Office of the Interconnection~~ shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule, for demand reductions measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBLdetermined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent highest load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. For the purposes of calculating the CBL for weekdays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. NERC holidays;

2. Event day(s), as defined in subsection (a)(i)(3) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

3. Weekdays the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection;

4. Any weekday the event period usage is less than 25% of the average event period usage for the five days.

iii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. For the purposes of calculating the CBL for Saturdays or Sundays/NERC holidays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. Event day(s), as defined in subsection (b)(i)(1) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

2. Saturday or Sundays/NERC holidays where the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection.

iii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use costumer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant, Load Serving Entity, electric distribution company, and/or the Office of the Interconnection ("Interested Parties") may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. Any proposal made pursuant to this section shall be provided to all other Interested Parties.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is received by all Interested Parties. If all Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon all Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.4 and 3.3A.5.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used soley to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Weather-Sensitive and Symmetric Additive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or “WSA”) or Symmetric Additive Adjustment for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment and Symmetric Additive Adjustment shall be calculated using the following applicable formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer’s on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index (“THI”) on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

The regression analysis will produce a slope (m), expressed in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer’s load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

WSA = [(m x THIEVENT DAY) + b]/[(m x THICBL DAYS) +b]

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the

Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer’s location may be used if it can be shown that the temperature at the end-use customer’s location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.

- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer’s historical, seasonal, on-peak non-coincident peak load.

Symmetric Additive Adjustment

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by PJMSettlement~~the Office of the Interconnection~~ the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) In cases where the demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer

Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(d) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer's zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant's zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, PJMSettlement~~the Office of the Interconnection~~ shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer's demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(d) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

3.3A.6 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.4 and 3.3A.5 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market.

(b) Demand reductions that do not meet the requirements of Section 3.3A.6(a) shall not be eligible for settlement pursuant to Sections 3.3A.4 and 3.3A.5. Examples of settlements prohibited pursuant to this Section 3.3A.6(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint, provided that, the foregoing notwithstanding, settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a), then the Office of the Interconnection shall suspend the Economic Load Response

Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.7 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to 3.3A.4 and 3.3A.5 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted. PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

  i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

  ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. An Economic Load Response Participant’s daily settlement will be denied by PJM based on the following criteria:

1) Submission of settlement for self schedule energy in the Real-time Energy Market where only some of the self scheduled hours have been included in the daily settlement submission; or

2) Daily settlement with an estimated value less than Five U.S. Dollars ($5.00); or

3) Daily settlement has a significant number of uneconomic hours *where the Locational Marginal Price is less than or equal to the generation plus the transmission portion of an end-use customer’s retail rate or price*.

vi. The electric distribution company and the Load Serving Entity may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, retail rate, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.7. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement~~The Office of the Interconnection~~ shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or buses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

~~The Office of the Interconnection~~PJMSettlement on behalf of PJM shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding

Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement~~the Office of the Interconnection~~ each hour will be the aggregate net amounts determined as specified in this Schedule. PJMSettlement~~The Office of the Interconnection~~ shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead ~~Congestion~~ Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) ~~A~~In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement~~the LLC~~ by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of

Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Rights. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of the buses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period.

Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the LLC~~Members (or the Office of the Interconnection on behalf of the Members)~~ and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owners with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to Section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to Section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to Section 5.2.2(e) and the award of Financial Transmission Rights pursuant to Section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction. An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to Section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual Financial Transmission Rights auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term Financial Transmission Rights auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term Financial Transmission Rights auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term FTR auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of three rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 3 months after the first round, and the third round shall be conducted approximately 3 months after the second round. In each round 1/3 of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three business days ending at 5:00 p.m. on the last day. PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five business days after the close of the bidding period for each round. If the Office of the Interconnection discovers an error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of prices for that auction. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

(i) The periods covered by long-term Financial Transmission Rights auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.

(ii) On-Peak, off-peak and 24-hour Financial Transmission Rights obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights Auction. Eligible receipt and delivery points in long-term Financial Transmission Rights Auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Financial Transmission Rights auctions conducted to liquidate a defaulting Members' Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in the Section 7.3.9 herein and with the standards and procedures set forth in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offer or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period,

market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.5 of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any

offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.3.9 Liquidation of Financial Transmission Rights in the Event of Member Default.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the PJM Operating Agreement or PJM Tariff, the Office of the Interconnection shall, as soon as practicable after such default is declared, initiate the following procedures to close out and liquidate the Financial Transmission Rights of a Member:

a) The Office of the Interconnection shall close out the defaulting Member's positions as of the date of its default, by unilaterally accelerating and terminating all forward Financial Transmission Rights positions.

b) The Office of the Interconnection shall post on its website all salient information relating to the closed out portfolio of Financial Transmission Rights.

c) All current planning period Financial Transmission Right positions within the defaulting Members' Financial Transmission Right portfolio will be offered for sale in the next available monthly balance of planning period Financial Transmission Rights auction at an offer price designed to maximize the likelihood of liquidation of those positions.

d) Financial Transmission Rights positions that do not settle until the next or subsequent planning period will be offered into the next available Financial Transmission Rights auction (taking into account timing constraints and the need for an orderly liquidation) where, based on the Office of Interconnection's commercially reasonable expectation, such positions would be expected to clear. In the event that the next scheduled Financial Transmission Rights

auction is more than two (2) months subsequent to the date that the Office of the Interconnection declares a Member in default, a specially scheduled Financial Transmission Rights auction may be conducted by the Office of the Interconnection. The entire portfolio of the defaulting Member's Financial Transmission Rights will be offered for sale at an offer price designed to maximize the likelihood of liquidation of those positions.

e) The Financial Transmission Right positions comprising the defaulting Member's portfolio that are liquidated in a Financial Transmission Rights auction should avoid setting the price in the auction at the bid prices with which they were initially submitted. In the event that any of the closed out Financial Transmission Rights would set price based on the auction's preliminary solution, then only one-half of each Financial Transmission Rights position will be offered for sale and the auction will be re-executed. In the event that any Financial Transmission Rights position that has been closed out once again sets price, then all Financial Transmission Rights scheduled to be liquidated will be removed from the affected auction and the auction will be re-executed excluding the closed out Financial Transmission Right positions. Financial Transmission Right positions that are not liquidated will then be offered in the next available auction or specially scheduled auction, as appropriate.

f) The liquidation of the defaulting Members' Financial Transmission Rights portfolio pursuant to the foregoing procedures shall result in a final liquidated settlement amount. The final liquidated settlement amount will be included in calculating a Default Allocation Assessment as described in Section 15.1.2A(I) of the PJM Operating Agreement. If the Office of the Interconnection is unable to close out and liquidate a Financial Transmission Rights position under the foregoing procedures, the close out shall be deemed void and the defaulting Member shall remain liable for the full final value of its default, such full final value being realized at the normal time for performance of the Financial Transmission Rights position.

In all other respects, Financial Transmission Rights terminated pursuant to this section shall be liquidated pursuant to the appropriate provisions and procedures set forth in the PJM Manuals.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal

to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has

Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue

Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement~~the LLC~~ by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, ~~the Office of the Interconnection~~PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com) for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than eleven business days prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, given that the electric distribution company and load serving entity must comply with a ten business day review period. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection with ten or fewer business days remaining prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, then the registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration prior to the registration deadline. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection. The following general steps will be followed:

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

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An 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) an end-use customer's participation in PJM's Emergency Load Response program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting and conditioning the end-use customer participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation and is received by the Office of the Interconnection on or after June 1 of the applicable Delivery Year, then the existing end-use customer’s registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation and is received by the Office of the Interconnection before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer’s participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

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

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

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the 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 Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer’s participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration deadline established before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer’s participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response participant’s registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements, the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer’s Demand Resource (as defined in the Reliability Assurance Agreement) registration before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer’s participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer’s registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers’ Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency 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.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program or notifies the requesting participant and appropriate Load Serving Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option Participants shall be the amount PJM dispatches up the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP otherwise in use for settlement of the given load or $500/MWh. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

1.1A Counterparty.

PJMSettlement is the Counterparty to obligations and all payments and distributions associated with underfrequency relay obligations and charges pursuant to this Schedule 7.

PJM Tariff Revisions

(Non-Redlined Version)

Definitions – C-D

1.3BB.03 Cancellation Costs:

The Costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Part IV and/or Part VI of the Tariff.

1.3C Capacity Interconnection Rights:

The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

1.3D Capacity Resource:

Shall have the meaning provided in the Reliability Assurance Agreement.

1.3E Capacity Transmission Injection Rights:

The rights to schedule energy and capacity deliveries at a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

1.3F Commencement Date:

The date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

1.4 Commission:

The Federal Energy Regulatory Commission.

1.5 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.5.01 Confidential Information:

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

1.5A Consolidated Transmission Owners Agreement:

The 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.

1.5B Constructing Entity:

Either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

1.5C Construction Party:

A party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

1.5D Construction Service Agreement:

Either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

1.6 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.6A Control Zone:

Shall have the meaning given in the Operating Agreement.

1.6B Controllable A.C. Merchant Transmission Facilities:

Transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Part IV and Part VI of the Tariff.

1.6C Costs:

As used in Part IV, Part VI and related attachments to the Tariff, costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

1.6D Counterparty:

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 customer.

1.7 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.7A Customer Facility:

Generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Subparts A of Part IV of the Tariff.

1.7A.01 Customer-Funded Upgrade:

Any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Section 217 of the Tariff, or (ii) is voluntarily undertaken by a market participant in fulfilment of an Upgrade Request pursuant to Section 7.8 of Schedule 1 of the Operating Agreement. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

1.7A.02 Customer Interconnection Facilities:

All facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate 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.

1.7B Daily Capacity Deficiency Rate

Daily Capacity Deficiency Rate is as defined in Schedule 11 of the Reliability Assurance Agreement.

1.7C Deactivation:

The retirement or mothballing of a generating unit governed by Part V of this Tariff.

1.7D Deactivation Avoidable Cost Credit:

The credit paid to Generation Owners pursuant to section 114 of this Tariff.

1.7E Deactivation Avoidable Cost Rate:

The formula rate established pursuant to section 115 of this Tariff.

1.7F Deactivation Date:

The date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

1.7G Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

1.8 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Definitions – O – P - Q

1.27C Office of the Interconnection:

Office of the Interconnection shall have the meaning set forth in the Operating Agreement.

1.28 Open Access Same-Time Information System (OASIS):

The 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.

1.28A Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement:

That agreement dated as of April 1, 1997 and as amended and restated as of June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.28A.01 Option to Build:

The option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

1.28B Optional Interconnection Study:

A sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

1.28C Optional Interconnection Study Agreement:

The form of agreement for preparation of an Optional Interconnection Study, as set forth in Attachment N-3 of the Tariff.

1.29 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31A Part IV:

Tariff Sections 36 through 112 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31B Part V:

Tariff Sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31C Part VI:

Tariff Sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties:

The Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

1.32.01 PJM:

PJM Interconnection, L.L.C.

1.32A PJM Administrative Service:

The services provided by PJM pursuant to Schedule 9 of this Tariff.

1.32B PJM Control Area:

The Control Area that is recognized by NERC as the PJM Control Area.

1.32C PJM Interchange Energy Market:

The regional competitive market administered by the Transmission Provider for the purchase and sale of spot electric energy at wholesale interstate commerce and related services, as more fully set forth in Attachment K – Appendix to the Tariff and Schedule 1 to the Operating Agreement.

1.32D PJM Manuals:

The instructions, rules, procedures and guidelines established by the Transmission Provider for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

1.32E PJM Region:

Shall mean the aggregate of the PJM West Region, the VACAR Control Zone, and the MAAC Control Zone.

1.32F PJM South Region:

The VACAR Control Zone.

1.32.F.01 PJMSettlement:

PJM Settlement, Inc. (or its successor).

1.32G PJM West Region:

The PJM West Region shall include the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Operating Companies; The Dayton Power and Light Company; and the Duquesne Light Company.

1.33 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.33A Point of Interconnection:

The point or points, shown in the appropriate appendix to the Interconnection Service Agreement and the Interconnection Construction Service Agreement, where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

1.34 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.36.01 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.36A Pre-Expansion PJM Zones:

Zones included in this Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

1.36A.01 Project Financing:

Shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

1.36A.02 Project Finance Entity:

Shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

1.36B Queue Position:

The priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Part VI.

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 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 pariticants 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 Schedules 3, 4, 5 and 6) 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. Sections 3.1 through 3.6 below list the six Ancillary Services.

3D [Reserved]

7 Billing and Payment

PJMSettlement shall issue bills and billing statements pursuant to the provisions in this section 7 in its own name and as agent for Transmission Provider, as applicable. Payment of bills pursuant to this section 7 shall be made for the benefit of PJMSettlement and Trasnmission Provider, as applicable.

7.1 Billing Procedure:

(a) Monthly Bills.

By the fifth business day of each month, PJMSettlement, in its own name and as agent for Transmission Provider, as applicable, shall issue a bill to Transmission Customers and other entities for monthly activity and detailing the charges and credits for all services furnished under the Tariff during the preceding month ("billing month"), excluding amounts billed pursuant to weekly bills for activity during the preceding month.

(b) Weekly Bills.

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

(c) Billing Statement.

PJMSettlement, in its own name and as agent for Transmission Provider, as applicable, shall provide Transmission Customers and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Transmission Customer's or other entity's activity during the billing month and amounts due, net of activity previously billed.

7.1A Payments:

(a) Monthly Bills.

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

(b) Weekly Bills.

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

(i) Municipal Electric Systems.

Recognizing that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments on a weekly bill issued pursuant to Section 7.1(b) when due, the Transmission Provider may allow a municipal electric system to make arrangement with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

(a) the Transmission Provider determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;

(b) the municipal electric system reimburses PJM for the actual cost of such working capital;

(c) the municipal electric system provides PJM with a binding representation that it has all legal right and authority to enter into the arrangement with PJM;

(d) PJMSettlement will continue to issue weekly bills to the municipal electric system in accordance with Section 7,1(b) above and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under Section 7.1A(a).;

(e) the aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;

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

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

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

(c) Form of Payments.

All payments tendered in satisfaction of a Transmission Customer's or other entity's obligations to PJMSettlement or Transmission Provider shall be in the form of immediately available funds payable to PJMSettlement, or by wire transfer to a bank named by PJMSettlement.

(d) Payments by PJMSettlement.

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

(e) Payment Calendar.

A comprehensive billing and settlement calendar will be posted on Transmission Provider's website prior to March 31 for the upcoming June – May annual period to communicate the schedule of holidays for settlement and billing purposes.

7.2 Interest on Unpaid Balances:

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by PJMSettlement.

7.3 Customer Default:

In the event the Transmission Customer or other entity (a) fails, for any reason, to make payment to PJMSettlement, for the benefit of PJMSettlement or the Transmission Provider, on or before the due date as described above, or (b) fails at any time to meet the Transmission Provider's creditworthiness requirements, and such failure is not corrected within two business days after the Transmission Provider notifies the Transmission Customer or other entity to cure such failure, a default by the Transmission Customer or other entity shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request; provided however, that (i) in the event that a state required retail access program provides for continuation of retail service to affected end-use customers by another supplier that is a Transmission Customer, then the Transmission Provider may, upon default by a Transmission Customer, immediately terminate Transmission Service to the defaulting Transmission Customer for the load of such end-use customers, and (ii) in the event that a Transmission Customer is taking service under Part II to serve load outside of the PJM Region, then the Transmission Provider may, upon default by a Transmission Customer, immediately terminate Transmission Service to the defaulting Transmission Customer. Billing disputes between the Transmission Provider and the Transmission Customer or other entity shall be addressed through the Transmission Provider's dispute resolution procedures, and shall not relieve the Transmission Customer or other entity of the obligation to make payment of all amounts due hereunder.

If the Transmission Customer fails to meet these requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy, or, in the case of a state required retail access program that provides for continuation of retail service to affected end-use customers by another supplier that is a Transmission Customer, immediately terminate Transmission Service as provided above.

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider, the Transmission Owners, PJMSettlement nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Liability:

Neither the Transmission Provider, a Transmission Owner, PJMSettlement, nor a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Transmission Customer, third party or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any Service Agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of the Transmission Provider, the Transmission Owner, PJMSettlement, or the Generation Owner, as the case may be.

To the extent that a Transmission Customer, third party or other person has a claim against the Transmission Provider, PJMSettlement, a Transmission Owner, or a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider the amount of any judgment or arbitration award on such claim entered in favor of the Transmission Customer, third party or other person shall be limited to the value of the Transmission Provider's assets or the Transmission Owner's assets or the Generation Owner's assets, as the case may be. The Transmission Customer, third party or other person may not seek to enforce any claims against the directors, managers, members, shareholders, officers or employees of the Transmission Provider, a Transmission Owner, or a Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider who shall have no personal liability for obligations of the Transmission Provider, a Transmission Owner, or a Generation Owner by reason of their status as directors, managers, members, shareholders, officers or employees of the Transmission Provider or a Transmission Owner or a Generation Owner; provided, however, that nothing herein contained shall affect the obligations of any member of the Transmission Provider or PJMSettlement under the Operating Agreement or this Tariff or any schedule hereunder.

10.3 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save each Transmission Owner, the Transmission Provider, PJMSettlement, and each Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider, and their directors, managers, members, shareholders, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's, PJMSettlement's, a Transmission Owner's, or a Generation Owner's (acting in good faith to implement or comply with the directives of the Transmission Provider) performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by such Transmission Owner, the Transmission Provider, or such Generation Owner acting in good faith to implement or comply with the directives of the Transmission Provider.

10.4 Limitation on Claims:

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

(b) For claims that arose prior to the effective date of Section 10.4 of the Tariff, the claimant shall have two years from the effective date to assert such claims.

II. POINT-TO-POINT TRANSMISSION SERVICE

References to section numbers in this Part II refer to sections of this Part II, unless otherwise specified.

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery. PJMSettlement shall be the Counterparty to the Point-To-Point Transmission Service transactions under this Tariff. As set forth in Attachment K, Section D, Point-To-Point Transmission Service transactions may give rise to several component charges and credits, which may offset one another, and such component charges and credits are not separate transactions from Transmission Service transactions.

23.1 Procedures for Assignment or Transfer of Service:

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider and PJMSettlement governing reassignments of transmission service prior to the date on which the reassigned service commences. PJMSettlement shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider and PJMSettlement or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider and PJMSettlementor the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

27A Distribution of Revenues from Non-Firm Point-to-Point Transmission Service

Transmission revenues from Non-Firm Point-to-Point Transmission Service (other than the portion of such revenues equal to congestion charges and the revenues attributable to the Transitional Revenue Neutrality Charge) for a Billing Month shall be distributed to the Network Customers (including the Transmission Owners) and Transmission Customers purchasing Firm Point-to-Point Transmission Service in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service. PJMSettlement shall distribute all revenues attributable to the Transitional Revenue Neutrality Charge to Allegheny Power.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

References to section numbers in this Part III refer to sections of this Part III, unless otherwise specified.

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which each Transmission Owner utilizes the Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff. PJMSettlement shall be the Counterparty to the Network Integration Transmission Service transactions under this Tariff. As set forth in Attachment K, Section D, Network Integration Transmission Service transactions may give rise to several component charges and credits, which may offset one another, and such component charges and credits are not separate transactions from Network Integration Transmission Service transactions.

34 Rates and Charges

The Network Customer shall pay PJMSettlement, in its own name, or as agent for the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, PJM Administrative Service, any applicable Transmission Enhancement Charge(s) and applicable study costs, consistent with Commission policy, along with the following:

119 Cost of Service Recovery Rate:

Notwithstanding anything to the contrary in Part V of this Tariff, a Generation Owner with a generating unit proposed for Deactivation that continues operating beyond its proposed Deactivation Date may file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V ("Cost of Service Recovery Rate"). In the event that the Generation Owner or its Designated Agent files a rate pursuant to this section 119, the Generation Owner shall not be eligible to receive Deactivation Avoidable Cost Credits or any compensation pursuant to section 117 of this Tariff, except as provided pursuant to this section 119, and PJMSettlement shall pay the Generation Owner the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving Deactivation Avoidable Cost Credits, prior to filing an Cost of Service Recovery Rate, such Deactivation Avoidable Cost Credits will cease as of the date that the Generation Owner or its Designated Agent files its Cost of Service Recovery Rate, and PJMSettlement shall begin paying the Generation Owner or its Designated Agent the Cost of Service Recovery Rate accepted by the Commission commencing on the effective date established by the Commission for the rate. In the event the Generation Owner or its Designated Agent already is receiving compensation pursuant to section 117 of this Tariff, prior to filing an Cost of Service Recovery Rate, such compensation shall continue until the effective date established by the Commission for the Cost of Service Recovery Rate.

A generating resource owner shall direct all inquiries regarding avoidable expenses to the Market Monitoring Unit. If a generating resource owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may petition the Commission for an order that would require the generating resource owner to include an appropriate cost component. This provision is duplicated in section IV.2 of Attachment M – Appendix.

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company	0.0797
Duquesne Light Company[1]	0.0520

1Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region:

$0.1019/MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	0.50
Baltimore Gas and Electric Company	0.80
Delmarva Power & Light Company	0.77
PECO Energy Company	2.68
PP&L, Inc. Group	1.36
Potomac Electric Power Company	0.33
Public Service Electric and Gas Company	2.64
Jersey Central Power & Light Company	1.30
Metropolitan Edison Company	0.43
Pennsylvania Electric Company	0.66
Rockland Electric Company	0.20
Commonwealth Edison Company	37.62
AEP East Operating Companies	47.90
The Dayton Power and Light Company	2.36
Duquesne Light Company	0.45

SCHEDULE 2
Reactive Supply and Voltage Control from
Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in section 3.2.3B of the Appendix to Attachment K.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation or other source Owner Monthly Revenue Requirement
>
> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation or other source Owner Monthly Revenue Requirement * Adjustment Factor
>
> Where:
>
> > Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement

for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation or other source Owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation or other source Owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source Owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity in the month (not curtailed by PJM) divided by 24.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

Each month, the Transmission Provider shall pay each Generation or other source Owner an amount equal to the Generation or other source Owner's monthly revenue requirement as accepted or approved by the Commission. In the event a Generation or other source Owner sells a Generation Capacity Resource(s) which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation or other source Owner's Zone may be allocated as agreed to by the owners of Generation Capacity

Resources in that Zone. Such Generation or other source Owners shall inform Transmission Provider of any such agreement. In the absence of agreement among such Generation or other source Owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

SCHEDULE 3
Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. The Transmission Provider shall administer the purchases of Regulation Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Regulation Service in the PJM Interchange Energy Market; 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 of generation resources by a customer to satisfy its Regulation obligation.

For regulation not satisfied by individual Transmission Owners on behalf of their Native Load Customers, Network Customers or other Transmission Customers serving load in the PJM Region, the Transmission Provider will order the lowest cost alternative for regulation in service as needed to meet the regulation requirements of each Regulation Zone (as set forth in the PJM Manuals), as specified below:

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from generators located within the metered electrical boundaries of such Regulation Zone. Generators offering regulation shall comply with applicable standards and requirements for regulation capability and dispatch specified in the procedures of the Office of the Interconnection.

b. The Office of the Interconnection shall obtain and maintain an amount of regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its procedures.

c. The regulation range of a unit shall be at least twice the amount of regulation assigned.

d. A unit capable of automatic energy dispatch that is also providing regulation shall have its energy dispatch range reduced from the regulation range by twice the amount of the regulation provided. The amount of regulation provided by a unit shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the amount of regulation shall be added to the unit’s normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.

e. Qualified regulation must satisfy the verification tests described in the procedures of the Office of the Interconnection.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its regulation obligation from its own resources capable of performing regulation service, by contractual arrangements with others able to provide regulation service on a comparable basis, or by purchases from, as applicable, the regulation market in the MAAC Control Zone, the regulation market in the VACAR Control Zone or the regulation market in the PJM West Region.

g. The Office of the Interconnection shall obtain regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Control Zone requirements not otherwise satisfied by a Transmission Owner, Network Customer or other Transmission Customer, in accordance with Section 1.11.4(b) of Attachment K-Appendix.

h. The Office of the Interconnection shall dispatch resources for regulation by sending regulation signals and instructions to resources from which regulation service has been offered, in accordance with the procedures of the Office of the Interconnection. Those resources 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. Those providing regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

i. Each Transmission Owner (on behalf of its Native Load Customers), Network Customer or other Transmission Customer serving load within a Control Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Control Zone for such hour, based on the entity's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Control Zone for such hour.

j. An entity supplying regulation at the direction of the Office of the Interconnection in excess of its hourly regulation obligation shall be credited for each increment of such regulation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix. A Transmission Owner, Network Customer or other Transmission Customer that does not meet its hourly regulation obligation shall be charged for regulation dispatched by the Office of the Interconnection to meet such obligation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix.

SCHEDULE 4
Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner, Transmission Customer, and Network Customer must purchase Energy Imbalance Service through the Transmission Provider, with PJMSettlement acting as the Counterparty, or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service. For purposes of Energy Imbalance Services, if a Point of Delivery serves more than one Transmission Owner or Network Customer, the Energy Imbalance Service and any associated charges will be computed by the Transmission Provider for the Point of Delivery and the allocation of the service and associated charges shall be the responsibility of the meter operator of the Point of Delivery.

For each Transmission Owner, Transmission Customer receiving service under Part II of this Tariff, and Network Customer, Energy Imbalance Service is considered to be PJM interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of this Tariff. The Transmission Provider shall administer the purchases by customers of Energy Imbalance Service. PJMSettlement shall be the Counterparty to the purchases by customers of Energy Imbalance Service.

SCHEDULE 5
Operating Reserve - Synchronized Reserve Service

Synchronized Reserve Service is needed to serve load immediately in the event of a system contingency. Synchronized Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service or eligible Demand Resources. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner and Network Customer must purchase this service from the Transmission Provider. The amount of and charges for Synchronized Reserve Service, as defined in accordance with NERC operating policies, will be accounted and paid for as set forth in Section 3.2.3A of the Appendix to Attachment K. The Transmission Provider shall administer the purchases by customers of Synchronized Reserve Service. PJMSettlement shall be the Counterparty to the purchases by customers of Synchronized Reserve Service in the PJM Interchange Energy Market; 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 of generation resources by a customer to satisfy its Synchronized Reserve obligation.

SCHEDULE 6
Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. Each Transmission Owner and Network Customer must purchase this service from the Transmission Provider. The amount of and charges for Supplemental Reserve Service will be accounted and paid for as part of the Operating Reserves in accordance with sections 3.2.3 and 3.2.3A.01 of the Appendix to Attachment K. The Transmission Provider shall administer the purchases by customers of Supplemental Reserve Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Supplemental Reserve Service in the PJM Interchange Energy Market; 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 Supplemental Reserve.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider, in conjunction with the Transmission Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5 or 6 below.

5. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall

commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in section 18, and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

6A. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6.

Performance Standards and Outage Restrictions

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

<u>Testing</u>

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to

two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its commitment pursuant to section 5 or section 6, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6A.

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6, as applicable, or (ii) the formulas set forth in section 18 of this Schedule 6A for the commitment term set forth in section 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. Requests for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to section III of Attachment M – Appendix and the PJM Manuals. The Market Monitoring Unit and the generator owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements. The Black Start Service generator owner may submit Black Start Service revenue requirements that it chooses, provided that (i) it has participated in good faith with the process described in this section and in section III of Attachment M - Appendix, (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Service generator owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff.

In the event that the Black Start Service generator owner and Market Monitoring Unit cannot agree on the level of each component included in the calculation of the Black Start Service revenue requirements, and the Black Start Service generator owner submits its own values to the

Office of the Interconnection that are inconsistent with the Market Monitoring Unit's determination, the Office of the Interconnection shall determine whether to accept such values subject to the requirements of the Tariff and the PJM Manuals. If the Office of the Interconnection does not accept the values submitted by the Black Start Service generator owner in such case, the Black Start Service generator owner may file its proposed values with the Commission for approval. Pursuant to section III of Attachment M - Appendix, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Service generator owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission. No change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months. The Transmission Provider will presume that any FERC-approved cost recovery plan would be the exclusive basis for the recovery of a Black Start Unit's recovery of its costs during the applicable term.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

where:

Fixed BSSC

Black Start Units with a commitment established under section 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following formula:

CONE * 365 * Black Start Unit Capacity * X

Where:

"CONE" is the then current net Cost of New Entry for the CONE Area where the Black Start Unit is located as set forth in Section 5.10 of Attachment DD.

"Black Start Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW.

X is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start

Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under section 5, X shall be .01 for Hydro units, .02 for Diesel or CT units.

Black Start Units with a commitment established under section 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following formula:

Black Start Capital Cost * CRF

Where:

"Black Start Capital Costs" is the capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit.

"CRF" or "Capital Recovery Factor " is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table:

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Task Force Manual. Such costs shall include those incurred by a

Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost of Element Guidelines in the PJM Manauls.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall cacluate Fuel Storage Costs or "FSC" as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit.
"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.
"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1.
"MTSL" is the "minimum tank suction level" and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor for Black Start Units with a commitment established under section 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

Credits

20. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units.

21. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

22. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider and Applicable Regional Reliability Council criteria for Black Start Service and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

23. Zonal rates will be based on Black Start Service capability of generation units nominated by each transmission zone and allocated to network service customers and point-to-point reservations.

24. Revenue requirements for Black Start Units nominated by a Transmission Owner as critical (regardless of zonal location) will be allocated to the nominating Transmission Owner's zone.

25. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity in the month (not curtailed by PJM) divided by 24.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	32.114	2.676	0.6176	0.1235	0.0882
ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone 5/	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone					

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all 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. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, as defined in Attachment DD to this Tariff, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of \$3.60/kw/year, \$0.30/kw/mo., \$0.0692/kw/week, \$0.0099/kw/day-off-peak, or \$0.0138/kw/day-

on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 11
[Reserved]

SCHEDULE 12
Transmission Enhancement Charges

(a) Establishment of Transmission Enhancement Charges. One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements (as defined in Section 1.38C of the Tariff) by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. ("Coordinated System Plan"). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates PJMSettlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan or the Coordinated System Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

(1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;

(2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC's rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or

(3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a "Transmission Enhancement Charge." Transmission Enhancement Charges of one or more Transmission Owners shall be established in accordance with this Schedule 12. Transmission Enhancement Charges of one or more transmission owners within the Midwest Independent System Operator, Inc. ("MISO") shall be determined in accordance with to the MISO Tariff.

(b) Designation of Customers Subject to Transmission Enhancement Charges.

(i) Regional Facilities and Necessary Lower Voltage Facilities. Transmission Provider shall assign on a region-wide basis cost responsibility for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are (1) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that operate at or above 500 kV ("Regional Facilities"), or (2) new

Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan ("Necessary Lower Voltage Facilities") as follows:

(A) Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated annually among Responsible Customers as defined in this Schedule 12 on an annual load-ratio share basis using, consistent with section 34.1 of the Tariff, the applicable zonal loads at the time of each Zone's annual peak load from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.

(B) Cost responsibility allocated to an owner of a Merchant Transmission Facility pursuant to subsection (A) above shall be based on the Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility or on the planned Firm Transmission Withdrawal Rights associated with its Merchant Transmission Facility for which it has executed an Interconnection Service Agreement.

(C) (1) Except for transformers that are an integral component of a Regional Facility, transformers with low-side voltages below 500 kV shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that operate below 500 kV and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.

(D) Transmission Provider shall designate in the Schedule 12-Appendix the cost responsibility allocations determined pursuant to this subsection (b)(i) of this Schedule 12.

(ii) Cost Responsibility Assignment Procedures For Other Facilities Pursuant To Settlement In Docket Nos. ER06-456-000, et al. Pursuant to Schedule 6 of the Operating Agreement, Transmission Provider is required to assign cost responsibility for Required Transmission Enhancements based on the Transmission Provider's assessment of the contributions to the need for, and benefits expected to be derived from, each Required Transmission Enhancement. In Docket Nos. ER06-456-000, et al., the FERC approved a "Settlement Agreement And Offer Of Partial Settlement" filed on September 14, 2007, ("Docket No. ER06-456 Settlement"), that among other things provides procedures and methodologies for Transmission Provider to assign cost responsibility in accordance with Schedule 6 of the Operating Agreement for (1) Lower Voltage Facilities as defined in subsection (b)(iii) of this Schedule 12, (2) below 500 kV spare parts, replacement equipment, and circuit breakers and associated equipment, and (3) economic-based Required Transmission Enhancements that as planned will operate below 500 kV (collectively "Applicable Facilities"). The procedures set forth in subsections (b)(iii), (iv), (v) and (vi) of this Schedule 12 shall apply to (1) the assignments of cost responsibility for Applicable Facilities filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, and (2) the assignment of cost responsibility for Applicable Facilities included in Regional Transmission Expansion Plans approved by the PJM Board after June 1, 2007, unless and until a different method for determination of cost responsibility assignments is allowed into effect by the FERC. Notwithstanding any otherwise applicable filed rate and prior notice requirements of the Federal Power Act, in accordance with the Docket No. ER06-456 Settlement, the assignments of cost responsibility determined by Transmission Provider pursuant to subsections (b)(iii), (iv), (v) and (vi) of this Schedule 12 as reflected in Schedule 12-Appendix to the Tariff are subject to refunds, surcharges, and interest calculated pursuant to 18 C.F.R. § 35.19a, if and as required by FERC, based on an order on the hearing concerning issues applicable to Merchant Transmission Facilities established in PJM Interconnection, L.L.C., 119 FERC ¶ 61,067 (2007). The treatment of Merchant Transmission Facilities in the distribution factor or "DFAX" analysis described in subsection (b)(iii) of this Schedule 12, including but not limited to, the use of "Interim Values" (fifty percent of existing or planned Firm Withdrawal Rights of a Merchant Transmission Facility for the purposes of modeling a Merchant Transmission Facility in the determination of cost responsibility assignments for an "Interim Period" pending the outcome of the hearing on issues applicable to Merchant Transmission Facilities) is subject to all provisions of the Docket No. ER06-456 Settlement, and is specifically without prejudice to any position a party may take at the hearing described above and is not intended to influence the outcome of such hearing or to authorize in any way for any other purpose the Interim Values that are used during the Interim Period as part of the Docket No. ER06-456 Settlement.

(iii) Lower Voltage Facilities. Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues; (b) as planned will operate below 500 kV; and (c) are not "Necessary Lower Voltage Facilities" as defined in section (b)(i) of this Schedule 12 (collectively "Lower Voltage Facilities"), as follows:

(A) Cost responsibility for a Lower Voltage Facility shall be assigned pursuant to subsection (b)(iii)(C) of this Schedule 12 when the good faith estimate of the cost of the Lower Voltage Facility prepared in connection with the development of the Regional Transmission Expansion Plan and provided to the PJM Board at the time the Lower Voltage Facility is included for the first time in the Regional Transmission Expansion Plan equals or exceeds $5 million. The determination of whether the estimated costs of a Lower Voltage Facility equals or exceeds this threshold shall be based solely on such good faith estimate of the cost of the Lower Voltage Facility, regardless of the actual costs incurred. For the purpose of applying this $5 million threshold, the estimated cost of a Lower Voltage Facility shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the same time for inclusion in the Regional Transmission Expansion Plan that collectively are intended to mitigate a specific reliability criteria violation or set of related violations.

(B) Cost responsibility for a Lower Voltage Facility, the estimated costs of which do not equal or exceed the $5 million threshold described in subsection (b)(iii)(A) of this Schedule 12, shall be assigned to the Zone where the Lower Voltage Facility is to be located. In the event that a Lower Voltage Facility, the estimated costs of which do not equal or exceed the $5 million threshold, consists of a single transmission element or multiple transmission elements to be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of the transmission elements located in such Zone. Merchant

Transmission Facilities shall not be assigned cost responsibility for Lower Voltage Facilities the estimated costs of which do not equal or exceed the $5 million threshold.

(C) To assign cost responsibility for Lower Voltage Facilities, the estimated costs of which equal or exceed the $5 million threshold described in subsection (b)(iii)(A) of this Schedule 12, Transmission Provider shall use the DFAX analysis described in this subsection (b)(iii)(C) of Schedule 12 that takes into account the contributions of loads and Merchant Transmission Facilities to the reliability criteria violations for which Lower Voltage Facilities are identified as solutions.

(1) For purposes of the assignment of cost responsibility under this section (b)(iii)(C) of Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the effect of the load of each Zone or Merchant Transmission Facility on the transmission constraint that requires the Lower Voltage Facility, as determined by a power flow analysis. In general, a distribution factor can be represented as:

Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted

Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility

Pre-shift power flow = Megawatt flow over the constrained transmission element before the incremental megawatt transfer

After-shift power flow = Megawatt flow over the constrained transmission element after the incremental megawatt transfer

When calculating such distribution factors:

(a) All distribution factors are calculated with respect to a constrained transmission facility that has been modeled to exceed its capability in violation of reliability criteria or to address operational adequacy and performance issues, requiring the addition of the Lower Voltage Facility identified in the Regional Transmission Expansion Plan to resolve the identified violation(s). The distribution factor is calculated for the transmission facility prior to the addition of the reinforcements identified to resolve the violation(s).

(b) Contributions to a criteria violation are determined based on distribution factors to the aggregate load within a Zone or, in the case of a Merchant Transmission Facility, distribution factors determined to the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(c) In the event that a violation is modeled to occur with one or more transmission facilities removed from service, the distribution factor will be calculated with these facilities removed from service.

(d) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a constrained transmission facility to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(e) All values and inputs used in the calculation of the distribution factor shall be the same values and inputs as used in the basecase for the Regional Transmission Expansion Plan.

(2) In the DFAX analysis, to determine the impact of zonal loads and Merchant Transmission Facilities on a constrained facility, Transmission Provider shall calculate a distribution factor for each Zone and each Merchant Transmission Facility by modeling a transfer from all generation in the PJM Region (a) individually to the loads in each Zone and (b) individually to each Merchant Transmission Facility based on (i) an Interim Value as specified in the Docket No. ER06-456 Settlement of fifty percent of its associated existing or planned Firm Transmission Withdrawal Rights, as applicable, identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility, or (ii) such other value if any at all (referred to herein as a "Final Value") as determined to be appropriate by the FERC based on the outcome of the hearing on the issues applicable to Merchant Transmission Facilities in Docket Nos. ER06-456-000, et al. To establish the impact of the zonal load or Merchant Transmission Facility, in megawatts, on a constrained facility, the distribution factor on a constrained facility associated with the resulting transfer modeled by the Transmission Provider to an individual Zone or a Merchant Transmission Facility shall be multiplied, as applicable, by (c) zonal peak load of the Zone being evaluated or (d) the Interim Value, or Final Value if any, as applicable, applied to (i) the existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility, for a Merchant Transmission Facility that is not yet in service. The products, so determined, for each Zone and each Merchant Transmission Facility, shall determine the relative allocation shares for each Zone and each Merchant Transmission Facility.

(3) In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

(4) In the DFAX analysis, Transmission Provider shall calculate assignments of cost responsibility based on all reliability criteria violations that contribute to the need for a Lower Voltage Facility. If one Lower Voltage Facility or group of Lower Voltage Facilities resolves multiple violations, to determine a Zone or Merchant Transmission Facility's

cost responsibility for such facility, the Zone's and Merchant Transmission Facility's individual megawatt contribution to each reliability criteria violation (determined in subsection (b)(iii)(C)(2) of this Schedule 12) shall be proportionally scaled up or down, so that the sum of the adjusted megawatt impacts equals the magnitude of the overload (the "overload" meaning the megawatt flow on the transmission element exceeding the applicable rating therefore violating the reliability criteria, as modeled in the Regional Transmission Expansion Plan). The Zone's or Merchant Transmission Facility's cost responsibility assignment shall be calculated as the ratio of (i) the sum of the contributions, in megawatts, of that Zone or Merchant Transmission Facility, to each of the reliability criteria violations, to (ii) the sum of the overloads, in megawatts, on the constrained facilities that are the subject of the reliability criteria violations. The foregoing notwithstanding, for the cost responsibility assignments for Lower Voltage Facilities already filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, Transmission Provider shall consider only the single worst reliability criteria violation associated with each Lower Voltage Facility.

(5) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Zones and Merchant Transmission Facilities to reflect (a) the boundaries of Locational Deliverability Areas ("LDAs"), as defined in Attachment DD to the Tariff, and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective ("CETO"), as defined in Attachment DD to the Tariff, associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. The contribution of each zonal load to the constraint shall be determined by multiplying the resulting distribution factor by the peak load of a Zone or an Interim Value or Final Value if any, as specified in subsection (b)(iii)(C)(2) of this Schedule 12, for a Merchant Transmission Facility, as applicable. For Zones and Merchant Transmission Facilities that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Zones or Merchant Transmission Facilities as above for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Zone or Merchant Transmission Facility in the calculation of the contribution to the constrained facility. A distribution factor threshold of 0.001 shall be applied to all cost responsibility assignment calculations such that any distribution factor less than 0.001 shall be set equal to zero.

(6) In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the ER06-456 Settlement.

(7) Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii)(C) of this Schedule 12 to the nearest one-hundredth of one percent.

(8) Transmission Provider shall not account for the ability to adjust use of phase angle regulators ("PARs") in the DFAX analysis described in subsection (b)(iii)(C) of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(iv) Below 500 kV Spare Parts, Replacement Equipment And Circuit Breakers. Transmission Provider shall assign cost responsibility for below 500 kV spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) Below 500 kV spare parts that are part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV spare parts independently included the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection shall be assigned to the Zone of the owner of the spare part.

(B) Below 500 kV replacement equipment that is part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) Below 500 kV circuit breakers and associated equipment that are part of the design specifications of a transmission element of a Lower Voltage Facility at the time the Lower Voltage Facility is first included in the Regional Transmission Expansion Plan shall be considered part of the Lower Voltage Facility for the purpose of applying the cost threshold described in subsection (b)(iii)(A) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the Lower Voltage Facility. Cost responsibility for below 500 kV circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Lower Voltage Facility as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment.

(v) Economic-Based Required Transmission Enhancements That As Planned Will Operate Below 500 kV. Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV as follows:

(A) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and are accelerations of reliability-based Required Transmission Enhancements as described in section 1.5.7(b)(i) of Schedule 6 of the Operating Agreement ("Acceleration Projects") by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii)(C) of this Schedule 12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices ("LMP Benefit") over the period that the reliability-based enhancement or expansion is to be accelerated ("LMP Benefits Methodology"). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement that as planned will operate below 500 kV equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the reliability-based Required Transmission Enhancement is accelerated (i.e. the period between the date the Required Transmission Enhancement actually goes into service and the date the Required Transmission Enhancement originally was scheduled to go in service as a Lower Voltage Facility in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the reliability-based Required Transmission Enhancement is accelerated, cost responsibility for such an Acceleration Project shall be assigned based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12. Subject to an order on the hearing noted in section (b)(ii) of this Schedule 12, the assignment of any cost responsibility for Acceleration Projects to a Merchant Transmission Facility shall be based upon its Interim Values or Final Value if any, as applicable.

(B) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and that are modifications to reliability-based Required Transmission Enhancements as described in section 1.5.7(b)(ii) of Schedule 6 of the Operating Agreement based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12.

(C) Transmission Provider shall assign cost responsibility for economic-based Required Transmission Enhancements that as planned will operate below 500 kV and are new enhancements or expansions that could relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement based on a Change in Load Energy Payment consistent with the methodology set forth in section 1.5.7(d) of Schedule 6 of the Operating Agreement. Cost responsibility shall be allocated based on each Zone's pro rata share of the Change in Load Energy Payment. The Change in Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in Load Energy Payment.

(vi) Finality of Cost Responsibility Assignment. Once a Lower Voltage Facility or an economic-based Required Transmission Enhancement that as planned will operate below 500 kV is included in the Regional Transmission Expansion Plan, any modification to the Lower Voltage Facility or economic-based Required Transmission Enhancement that as planned will operate below 500 kV, respectively, that subsequently is included in the Regional Transmission Expansion Plan shall be considered a separate additional project subject to its own cost responsibility assignment. Such subsequent modification shall not impact or be impacted by the cost responsibility assignments that already have been made for the previously approved Lower Voltage Facility or economic-based Required Transmission Enhancement, as applicable.

(vii) FERC Filing. Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Section 1.6 of Schedule 6 of the PJM Operating Agreement, the Transmission Provider shall designate in the Schedule 12-Appendix and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge ("Responsible Customers") based on the cost responsibility assignments determined pursuant to subsections (b)(i) through (v) of this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those made for the relevant Regional Facility, Necessary Lower Voltage Facility, Lower Voltage Facility, and economic-based Required Transmission Enhancement that as planned will operate below 500 kV in the Regional Transmission Expansion Plan or in the Coordinated System Plan.

(viii) MISO. For purposes of this Schedule 12, where the Responsible Customers are subject to the Open Access Transmission and Energy Markets Tariff for the Midwest Independent System Operator, Inc. ("MISO Tariff"), MISO shall be the Responsible Customer with respect to all such Required Transmission Enhancements. Cost responsibility with respect to Transmission Enhancement Charges for which MISO has been designated the Responsible Customer shall be allocated within MISO in accordance with the MISO Tariff.

(ix) Merchant Transmission Facilities. For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(c) Determination of Transmission Enhancement Charges. In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner's annual transmission revenue requirement associated with the Required Transmission Enhancement;

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible;

(3) A Transmission Owner's annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner's rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements; and

(4) Each Transmission Enhancement Charge assigned by the Transmission Provider to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Section 34.1 of the PJM Tariff. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge assigned by the Transmission Provider to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Section 25 of the PJM Tariff.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to Section (b) of this Schedule shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in Section (a), the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

(d) Recovery of Transmission Enhancement Charges.

(1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.

(2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to MISO in the case of Transmission Enhancement Charges established by one or more transmission owners within MISO to be distributed to said transmission owners in accordance with the MISO Tariff.

(e) Crediting of Revenue from Transmission Enhancement Charges. In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

EXHIBIT A TO SCHEDULE 14

Form of Service Agreement for
<u>Transmission Service over the Neptune Line</u>

1.0 This Service Agreement, dated as of ____________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider"), as administrator of Transmission Service over the Neptune Line, and ____________________________ ("Neptune Transmission Customer").

2.0 The Neptune Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Neptune Reservation under the Tariff.

3.0 If required, the Neptune Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Neptune Transmission Customer agrees to take and pay for the Neptune Reservation in accordance with the provisions of Schedule 14 of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

<u>Transmission Provider</u>
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

<u>Neptune Transmission Customer</u>

____

____

____

7.0 The Tariff, including Schedule 14, is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: ______________________ ______________________ ______________________
Name Title Date

Neptune Transmission Customer:

By: ______________________ ______________________ ______________________
Name Title Date

CERTIFICATION

I, ____________________, certify that I am a duly authorized officer of ______________________________ (Neptune Transmission Customer) and that ______________________________ (Neptune Transmission Customer) will not request service under this Service agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this ________ day of ______________, ____________.

____
(Notary Public)

My Commission expires: ______________________________

Specifications For Transmission Service Over Neptune Line

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted.

____

3.0 Point of Receipt: Raritan River (Sayreville) Substation in Sayreville, New Jersey

Delivering Party: ____

4.0 Point of Delivery: Newbridge Road Substation in Long Island, New York

Receiving Party: ____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability): ____

6.0 Designation of party(ies) subject to reciprocal service obligation: ____________________

____

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff and Schedule XX).

8.1 Neptune Reservation Charge: ______________________________

____

8.2 Neptune Service Administration Charges: ______________________

____

EXHIBIT A TO SCHEDULE 16

Form of Service Agreement for
Transmission Service over the Linden VFT Facility

1.0 This Service Agreement, dated as of ___________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the "Transmission Provider"), as administrator of Transmission Service on the Linden VFT Facility, and _________________________ ("Linden VFT Transmission Customer").

2.0 The Linden VFT Transmission Customer has been determined by the Transmission Provider to have a Completed Application for a Linden VFT Reservation under the Tariff.

3.0 If required, the Linden VFT Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Linden VFT Transmission Customer agrees to take and pay for the Linden VFT Reservation in accordance with the provisions of Schedule 16 of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497
Linden VFT Transmission Customer ______________________________ ______________________________ ______________________________

7.0 The Tariff, including Schedule 16, is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: __________________________ _______________________ ____________________
Name Title Date

Linden VFT Transmission Customer:

By: __________________________ _______________________ ____________________
Name Title Date

CERTIFICATION

I, ______________________, certify that I am a duly authorized officer of __________________________________ (Linden VFT Transmission Customer) and that __________________________________ (Linden VFT Transmission Customer) will not request service under this Service agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this _________ day of _______________, _____________.

____
(Notary Public)
My Commission expires: _________________________________

Specifications For Transmission Service Over Linden VFT Facility

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted.

____

3.0 Point of Receipt: VFT Switching Station in Linden, New Jersey

Delivering Party: ____

4.0 Point of Delivery: NYISO (at the Linden Cogen 345 kV ring bus in Linden, New Jersey)

Receiving Party: ____

5.0 Maximum amount of energy to be transmitted (Reserved Transmission Capability):
____

6.0 Designation of party(ies) subject to reciprocal service obligation: ____________________

____

____

____

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff and Schedule16).

7.1 Linden VFT Reservation Charge:
____

____

7.2 Linden VFT Service Administration Charges:
____

____

7.3 Linden VFT Transmission Enhancement Charges:

____

____

ATTACHMENT A

Form of Service Agreement For
Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between the Office of the Interconnection of PJM Interconnection L.L.C. (the Transmission Provider) as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Firm Point-To-Point Transmission Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities, Local Upgrades and/or Network Upgrades and any contingencies identified in the Upgrade Construction Service Agreement by and among Transmission Provider, Transmission Customer and ________[name of transmission owner constructing upgrades]________________ are completed, if applicable, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties or as otherwise specified in this Service Agreement.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representatives as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty)

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

____

____

____

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

8.0 For Short-Term Firm Point-To-Point Transmission Service requested under this Agreement, the confirmation procedures set forth in this section 8.0 shall apply. Whenever PJM notifies the Transmission Customer that a request for Short-Term Firm Point-To-Point Transmission Service can be accommodated, the Transmission Customer shall confirm, by the earlier of (i) 15 days after PJM approves the request for service, or (ii) 12:00 noon on the day before the Service Commencement Date, that it will commence the requested service. Failure of the Transmission Customer to provide such confirmation will be deemed a withdrawal and termination of the request for the service, and any deposit submitted with the request will be refunded with interest.

{Use the following Section 9.0 for Long-Term Firm Point-To-Point Transmission Service Requests that require construction of Direct Assignment Facilities, Local Upgrades, and/or Network Upgrades}

9.0 The Transmission Customer was notified by the Transmission Provider that the System Impact Study indicates that Firm Point-To-Point Transmission Service can not extend beyond one year from the commencement of service unless certain Direct Assignment Facilities, Local Upgrades, and/or Network Upgrades are constructed pursuant to the Tariff and in accordance with the terms and conditions of the Upgrade Construction Service Agreement by and among Transmission Provider, Transmission Customer, and __________________[name of Transmission Owner constructing upgrades]________. The required Local Upgrades, Network Upgrades and/or Direct Assignment Facilities are identified, including estimated costs and lead times to support the requested Firm Point-To-Point Transmission Service in that Upgrade Construction Service Agreement. Therefore, the Transmission Customer may not be able to exercise reservation/rollover priority rights, in whole or in part, which it may otherwise have pursuant to Section 2.2 of the Tariff upon the initial termination date of the Firm-Point-To-Point Transmission Service, unless and until the Local Upgrades, Network Upgrades and/or Direct Assignment Facilities are completed pursuant to the terms of the Upgrade Construction Service Agreement.

10.0 Rates for Long-Term Firm Point-To-Point Transmission Service shall apply pursuant to this Service Agreement and applicable provisions of the PJM Tariff. Transmission Customer will not be eligible for any credits against these rates for the value of the Local Upgrades, Network Upgrades and/or Direct Assignment Facilities it provides; its consideration for payment for Customer-Funded Upgrades will be the Long-Term Firm Point-To-Point Transmission Service described in the Transmission Service Agreement, and the associated Upgrade-Related Rights, as described in the Upgrade Construction Service Agreement.

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

Office of the Interconnection:

By: _________________________ _________________ ________________

Name Title Date

Counterparty:

By: _________________________ _________________ ________________

Name Title Date

Transmission Customer:

By: _________________________ _________________ ________________

Name Title Date

CERTIFICATION

I, ________________________, certify that I am a duly authorized officer of ___________________________________ (Transmission Customer) and that ___________________________________ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this ______ day of _________________, ________.

____
(Notary Public)

My Commission expires:__________________________

Specifications For Long-Term Firm Point-To-Point Transmission Service

l.0 Term of Transaction: ______________________________

Start Date: ______________________________

Termination Date: ______________________________

2.0 Description of capacity and energy to be transmitted including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________

Delivering Party: ______________________________

4.0 Point(s) of Delivery: ______________________________

Receiving Party: ______________________________

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Transmission Capability): ______________________________

6.0 Designation of party(ies) subject to reciprocal service obligation: ______________________________
____
____
____

7.0 Name(s) of any Intervening Systems providing transmission service: ______________________________
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ______________________________
____

8.2 System Impact and/or Facilities Study Charge(s):
____
____

8.3 Direct Assignment Facilities Charge:______________________________
____

8.4 Ancillary Services Charges: ______________________________________
____
____
____
____
____
____

8.5 Other Supporting Facilities Charge:_______________________________
____
____

ATTACHMENT A-1

Form Of Service Agreement For
The Resale, Reassignment Or Transfer Of
Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ____________ (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Counterparty:

____

____

____

Assignee:

____

____

____

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

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

Transmission Provider:

By:____________________________ ______________________ _______________
Name Title Date

Counterparty:

By:____________________________ ______________________ _______________
Name Title Date

Assignee:

By:____________________________ ______________________ _______________
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: __________________________________

Start Date: ____

Termination Date: ____________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:____________________________________

Delivering Party:____

4.0 Point(s) of Delivery:___________________________________

Receiving Party:_______________________________________

5.0 Maximum amount of reassigned capacity: ___________________

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: __________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:_____________________

____

8.4 Ancillary Services Charges: _______________________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

ATTACHMENT B
Form of Service Agreement For Non-Firm Point-To-Point
Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative as indicated below.

Transmission Provider (on behalf of Transmission Provider and Counterparty):
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Transmission Customer:

____

____

____

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

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

Office of the Interconnection:

By: ______________________________ __________________ _______________
Name Title Date

Counterparty:

By: _________________________ _________________ ________________

Name Title Date

Transmission Customer:

By: ______________________________ __________________ _______________
Name Title Date

CERTIFICATION

I, _____________________________, certify that I am a duly authorized officer of _____________________________________ (Transmission Customer) and that _____________________________________ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this _____ day of _____________, _______.

____
(Notary Public)

My Commission expires:______________________

ATTACHMENT F

Service Agreement For
<u>Network Integration Transmission Service</u>

1.0 This Service Agreement, dated as of ________________, is entered into, by and between the Office of the Interconnection of PJM Interconnection, L.L.C. (the Transmission Provider) as the administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and _____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a valid request for Network Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff.

3.0 Service under this agreement shall commence on the later of: (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Transmission Service in accordance with the provisions of the Tariff, including the Network Operating Agreement (which is incorporated herein by reference), and this Service Agreement as they may be amended from time to time.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider (on behalf of Transmission Provider and Counterparty):</u>
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

<u>Transmission Customer:</u>

____

____

____

6.0 The Tariff for Network Integration Transmission Service is incorporated herein and made a part hereof.

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

Office of the Interconnection:

By: ______________________ ________________ _______________
Name Title Date

Counterparty:

By: ______________________ ________________ _______________

Name Title Date

Transmission Customer:

By: ______________________ ________________ _______________
Name Title Date

CERTIFICATION

I, ____________________________, certify that I am a duly authorized officer of ____________________________________ (Transmission Customer) and that ____________________________________ (Transmission Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me this _____ day of _____________, _______.

____

(Notary Public)

My Commission expires:______________________

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

l.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and/or energy to be transmitted within the PJM Region (including electric control area in which the transaction originates).

____

3.0 Network Resources:____

4.0 Network Load:____

5.0 Designation of party subject to reciprocal service obligation:
____

6.0 Name(s) of any Intervening Systems providing transmission service:
____

____

7.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the tariff.)

7.1 Embedded Cost Transmission Charge:________________________

____

7.2 Facilities Study Charge:____________________________________

____

7.3 Direct Assignment Facilities Charge:_________________________

____

7.4 Ancillary Services Charge:__________________________________

____

7.5 Other Supporting Facilities Charge:_________________________

____

ATTACHMENT F-1

Form of Umbrella Service Agreement for
Network Integration Transmission Service
<u>Under State Required Retail Access Programs</u>

1.0 This Service Agreement dated as of __________, including the Specifications For Network Integration Transmission Service Under State Required Retail Access Programs attached hereto and incorporated herein, is entered into, by and between PJM Interconnection, L.L.C. ("Transmission Provider") as administrator of the Tariff, PJM Settlement Inc. ("Counterparty") as the counterparty, and ________________________, a transmission customer participating in a state required retail access program and/or a program providing for the contractual provision of default service or provider of last resort service ("Network Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Transmission Service under the Tariff and to have satisfied the conditions for service imposed by the Tariff to the extent necessary to obtain service with respect to its participation in a state required retail access program.

3.0 Service under this Service Agreement shall commence on ________________, and shall terminate on such date as mutually agreed upon by the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

4.0 The Transmission Provider agrees to provide, and the Network Customer agrees to take, Network Integration Transmission Service in accordance with the Tariff, including the Operating Agreement of the PJM Interconnection, L.L.C. ("Operating Agreement") (which is the Network Operating Agreement under the Tariff and is incorporated herein by reference) and this Service Agreement, as they may be amended from time to time.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u> <u>(on behalf of Transmission Provider and Counterparty)</u>

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Network Customer

____

____

____

IN WITNESS WHEREOF, the Transmission Provider and the Network Customer have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider

By:________________________ __________________________ ________
Name Title Date

Counterparty:

By: ______________________ _______________ ______________

Name Title Date

Network Customer

By:________________________ __________________________ ________
Name Title Date

SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE
PURSUANT TO STATE REQUIRED RETAIL ACCESS PROGRAMS

1.0 Term of Service: The term of service under this Service Agreement shall be from _________ until terminated by mutual agreement of the parties, unless state law or regulations specify a limited period for service or unless earlier terminated for default under Section 7.3 of the Tariff.

2.0 Network Operating Agreement: In accordance with Section 29.1 of the Tariff, the Network Customer must be a member of PJM Interconnection, L.L.C. and a signatory to the Operating Agreement.

3.0 Network Load and Network Resources: The Network Customer shall be responsible for the Transmission Provider receiving the information pertaining to Network Load, Network Resources, and Behind The Meter Generation described in this section. Such information shall be provided in accordance with procedures established by the Transmission Provider. With respect to service requests under this umbrella Service Agreement, the Transmission Provider will deem the provision of the information specified in this section as complying with the application requirements set forth in Section 29.2 of the Tariff.

3.1 Network Load: For Network Load within the PJM Region, the Network Customer shall arrange for each electric distribution company ("EDC") delivering to the Network Customer's load to provide directly to the Transmission Provider, on a daily basis, the Network Customer's peak load (net of operating Behind The Meter Generation, but not to be less than zero, unless such generation is separately metered and reported to PJM), by bus, coincident with the annual peak load of the Zone as determined under Section 34.1 of the Tariff. The peak load shall be expressed in terms of tenths of a megawatt and shall include all losses within the PJM Region, including other transmission losses, and distribution losses. Unless a more specific bus distribution is available, the EDC may provide a bus distribution for the Network Customer's peak load proportional to the bus distribution for all of the load in the Zone. The information must be submitted directly to the Transmission Provider by the EDC, unless the Transmission Provider approves in advance another arrangement. For Non-Zone Network Load, the Network Customer shall provide to the Transmission Provider, on a daily basis, the Network Customer's peak load, by interconnection at the border of the PJM Region, coincident with the annual peak load of such area as determined under Section 34.1 of the Tariff. The peak load for such Non-Zone Network Load shall be expressed in terms of tenths of a megawatt and shall not include losses within the PJM Region. Unless a more specific bus distribution is identified and node definition requested, a service request shall be granted upon submission of the information set forth in this Section 3.1 without any further confirmation procedures. If a Network Customer under this Service Agreement, prior to the commencement of service or at any time after the commencement of service, identifies a more specific bus distribution and requests a node definition for all or part of its Network Load that is served under state required retail access programs, the Network Customer shall notify both the Transmission Provider and the electric distribution company pursuant to the notification procedure and schedule set forth in the PJM manuals. The Transmission Provider, exercising its independent judgment and expertise, shall have the authority to resolve any difference of opinion that may arise between the Network Customer and the electic distribution company as to the applicable bus distribution or node definition. If confirmed, the more specific bus distribution will not be used for billing and settlement purposes, however, until the notification procedure set forth in the PJM manuals is completed, and in no event until June 1, to correspond with the commencement of the annual planning period.

3.2 Network Resources: The Network Customer, as necessary, shall designate from time to time its Network Resources. In the event the Network Resource to be designated is Behind The Meter Generation, the designation must be made before the commencement of a Planning Period as that term is defined in the Operating Agreement and will remain in effect for the entire Planning Period. Such Network Resources must be acceptable to the Transmission Provider as Network Resources in accordance with the Tariff and the Operating Agreement. Designations of resources that have not previously been accepted as Network Resources of any Network Customer or Transmission Customer shall include the information set forth in Section 29.2(v) of the Tariff. Changes in the designation of Network Resources will be treated as an application for modification of service. The Network Customer shall confirm the acceptance of a Network Resource within 15 days of the completion of a System Impact Study or 30 days after completion of a Facilities Study, as is applicable. The Transmission Provider will maintain a current list of Network Resources, which shall be updated from time to time.

3.3 Hourly Load: The Network Customer and/or the EDCs delivering to the Network Customer's load shall provide to the Transmission Provider, on a daily basis, hourly loads and an associated bus distribution for the Network Load. For Network Load within the PJM Region, hourly loads required under this Section shall include all losses within such area, including transmission losses, and distribution losses. The Network Customer shall notify the Transmission Provider whether the Network Customer or the EDC will submit the hourly loads. The submitted load values will include losses and shall be reduced using the applicable loss factor determined by the Transmission Provider whenever a billing determination is calculated under the Tariff without losses.

3.4 Energy Schedules: The Network Customer shall schedule energy for its hourly loads in accordance with the Appendix to Attachment K of the Tariff.

3.5 Interruptible Loads: The Network Customer shall inform or shall arrange for each EDC delivering to Network Customer's load to inform Transmission Provider about the amount and location of any interruptible loads included in the Network Load. This information shall include the summer and winter peak load for each interruptible load (had such load not been interruptible), that portion of each interruptible load subject to interruption, the conditions under which an interruption can be implemented, and any limitations on the duration and frequency of interruptions.

3.6 Procedures for Load Determination: The procedures by which an EDC will determine the peak and hourly loads reported to the Transmission Provider under Sections 3.1 and 3.3 may be set forth in a separate schedule to the Tariff for each EDC.

3.7 Behind The Meter Generation: For Behind The Meter Generation of a Network Customer that requires metering pursuant to section 14.5 of the Operating Agreement, the Network Customer shall arrange for the Transmission Owner or EDC to provide directly to Transmission Provider information pertaining to such Behind The Meter Generation and the total load at its location as necessary for PJM's planning purposes.

4.0 Energy Imbalance Service: The Network Customer will receive Energy Imbalance Service from the Transmission Provider in accordance with Schedule 4 of the Tariff. Energy Imbalance Service is considered to be PJM Interchange and will be charged at the hourly locational marginal price determined pursuant to Section 2 of the Appendix to Attachment K of the Tariff.

5.0 Reconciliation Billing: For Network Load within the PJM Region, to the extent required, the Transmission Provider will reconcile the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage, and provide corresponding charges and credits to Network Customer. Such reconciliation, if required, shall be made at the same rates as Energy Imbalance Service.

6.0 Designation of party subject to reciprocal service obligation: The Network Customer shall comply with Section 6 of the Tariff.

7.0 Name(s) of any Intervening Systems providing transmission service: To the extent any Network Resources are located outside the PJM Region, the list of Network Resources maintained by the Transmission Provider referenced in Section 3.2 of these specifications, shall identify any intervening systems needed to deliver those Network Resources to the Network Customer's retail load.

8.0 Charges: Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Embedded Cost Transmission Charge: The embedded cost transmission charge shall be determined in accordance with the formula set forth in Section 34 of the Tariff.

8.2 System Impact and Facilities Study Charges: To the extent Network Resources are located outside, or a new resource is added to, the PJM Region, a System Impact Study and/or Facilities Study Agreement and related charges may be required pursuant to Section 32 of the Tariff.

8.3 Direct Assignment Facilities Charge: To the extent that facilities or portions of facilities must be constructed by a Transmission Owner for the sole use or benefit of the Network Customer to accommodate the service requested by the Network Customer, the Network Customer shall be responsible for the cost of such Direct Assignment Facilities, and the charges for such facilities shall be specified at the time that the Transmission Provider determines the facilities that are needed to provide the requested service.

8.4 Ancillary Services Charge: In addition to Energy Imbalance Service, Transmission Provider shall bill the Network Customer for ancillary services in accordance with Schedules 1, 1-A, 2, 3, 5, 6, and 9 of the Tariff. To the extent required, the ancillary services charges shall also be reconciled based on any differences between the Network Customer's hourly energy responsibilities as initially reported to Transmission Provider and its hourly energy consumption based on, or estimated from, metered usage.

8.5 Other Supporting Facilities Charge: None.

8.6 **[Reserved]**

8.7 Other Charges: Transmission Provider shall charge Network Customer any and all other charges set forth in the Tariff applicable to providing Network Integration Service.

9.0 Designated Agent: To the extent that a Designated Agent for one or more Network Customers provides to the Transmission Provider any of the information required by these Specifications, it shall provide the information separately for each Network Customer.

CERTIFICATION

I, _______________________, certify that I am a duly authorized officer of

________________________________ (Network Customer) and that

________________________________ (Network Customer) will not request service under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of this Open-Access Transmission Tariff.

____
(Name)

____
(Name)

Subscribed and sworn before me this ____ day of _________, _________.

____
(Notary Public)

My Commission expires:_______________________

4. Offset of Credits and Debits to a Transmission User.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both amounts credited to a Transmission User in accordance with Section A(2) of this Attachment and amounts debited to a Transmission User in accordance with Section A(3) of this Attachment, and PJMSettlement shall exclude the Transmission User's transactions on the PJM Interchange Energy Market, in issuing a statement, invoice, or payment for the net amount owed to or by that Transmission User for Transmission Congestion Charges for any period.

Offset of Transmission Congestion Charges and Transmission Congestion Credits.

The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.

D. Transmission Service Components.

Transmission Congestion Charges and Transmission Congestion Credits, Ancillary Services charges and credits, Transmission Loss Charges, and allocations of Financial Transmission Rights auction revenues to a Transmission User are components of transmission service charges under Parts II and III of the Tariff and shall not give rise to separate transactions with PJMSettlement regarding the purchase or sale of electric energy.

1.1 Introduction.

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

1.5 Market Sellers.

1.5.1 Qualification.

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

1.5.2 Withdrawal.

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

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

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete the Economic Load Response 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.

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 appropriate electric distribution company or Load Serving Entity 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, and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. An 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity 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, and, if permitted, confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. If the 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, electric distribution company or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program 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 section 1.5A, including section 1.5A.3.

1.5A.4 Metering.

The Curtailment Service Provider is responsible to ensure that the Economic Load Response Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Economic Load Response Participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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 [Reserved for Future Use]

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 customer or its Curtailment Service Provider or Load Serving Entity 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"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

(a) A Batch Load Demand Resource may provide Synchronized Reserve or Day-Ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-Ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection's filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-Ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-Ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-Ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-Ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants may participate in the Day-ahead and Real-time Energy Markets as dispatchable or self-scheduled resources, provided that Demand Resources that are self-scheduled pursuant to Section 1.5A.9(a) shall not be dispatched by the Office of the Interconnection pursuant to this section.

(a) Self-scheduled Demand Resources shall be subject to the following requirements:

i. An Economic Load Response Participant self-scheduling a Demand Resource shall notify the Office of the Interconnection no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event;

ii. Economic Load Response Participants may self-schedule a Demand Resource intra-hour;

iii. A Notification pursuant to this section may be withdrawn or adjusted downward during the relevant event hour, but not after the even hour;

iv. A Notification submitted pursuant to this section shall include the start and stop times of the event and the amount of the demand reduction;

v. The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the Economic Load Response Participant has provided a Notification.

1.5A.10 Economic Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 500 kW of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. If all End-Use Customers in an aggregation are not subject to the same generation and transmission charges, the generation and transmission charge for the aggregation shall be the load weighted average of the generation and transmission charges for all End-Use Customers in the aggregation. The Economic Load Response Participant shall provide the load weighted average, the calculation of the load weighted average, and the supporting data to the Load Serving Entity and PJM. For the purposes of this section, the applicable generation and transmission charges are the charges an End-Use Customer would have otherwise paid the Load Serving Entity absent the demand reduction;

v. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.4 and 3.3A.5;

vi. 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 99 kW 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 499 kW of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vii. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource except for the 100 kW minimum load reduction requirement for energy or the 500 kW minimum load reduction requirement for Ancillary Services; and

viii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

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

1.6.2 Scope of Services.

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

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Operating Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

vi) Administer (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

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

1.6.3 Records and Reports.

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

1.6.4 PJM Manuals.

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

1.6A PJMSettlement

1.6A.1 Scope of Services

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (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 active load management, interruption of load, 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.

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

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses 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 eSchedules and Enhanced Energy Scheduler 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 eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy 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 eSchedules and Enhanced Energy Schedules 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 dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

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

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council 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 section 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 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 Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

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

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

1.7.18 Regulation.

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

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

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned.

(d) A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. 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

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

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

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

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

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

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

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling

Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets 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 eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

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

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 transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified 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.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, *this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals,* as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.5 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.5 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. 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).

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

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.5 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-Scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

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

1.10.4 Capacity Resources.

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

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

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load bus or busses 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 or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or busses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(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. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the

Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Regulation, Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section

1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed

Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues 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 Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the

Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = (\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}) / (\mathbf{UDSLAtime}_{t-1})$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated *balancing Operating Reserve* charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP *at the resource's bus does not meet or exceed* the *applicable* offer of the resource for at least four-5-minute intervals during one or more discrete *clock* hours *during each* period *the resource operated and produced MWs* during the relevant Operating Day. *If a resource operated* *and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.*

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each

Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the

Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (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 Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller’s internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule, for demand reductions measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent highest load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. For the purposes of calculating the CBL for weekdays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. NERC holidays;

2. Event day(s), as defined in subsection (a)(i)(3) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual

threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

3. Weekdays the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection;

4. Any weekday the event period usage is less than 25% of the average event period usage for the five days.

iii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. For the purposes of calculating the CBL for Saturdays or Sundays/NERC holidays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45 day period):

1. Event day(s), as defined in subsection (b)(i)(1) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

2. Saturday or Sundays/NERC holidays where the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection.

iii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant, Load Serving Entity, electric distribution company, and/or the Office of the Interconnection ("Interested Parties") may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. Any proposal made pursuant to this section shall be provided to all other Interested Parties.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is received by all Interested Parties. If all Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon all Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.4 and 3.3A.5.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used soley to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Weather-Sensitive and Symmetric Additive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or "WSA") or Symmetric Additive Adjustment for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment and Symmetric Additive Adjustment shall be calculated using the following applicable formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer's on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index ("THI") on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

The regression analysis will produce a slope (m), expressing in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer's load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

$$\text{WSA} = [(m \text{ x THIEVENT DAY}) + b]/[(m \text{ x THICBL DAYS}) + b]$$

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer's location may be used if it can be shown that the temperature at the end-use customer's location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.

- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer's historical, seasonal, on-peak non-coincident peak load.

Symmetric Additive Adjustment

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by PJMSettlement the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) In cases where the demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer’s Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer’s hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer’s hourly energy consumption is greater than the Customer Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(d) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer’s zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant’s zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, PJMSettlement shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer’s demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price

less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(d) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

3.3A.6 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.4 and 3.3A.5 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market.

(b) Demand reductions that do not meet the requirements of Section 3.3A.6(a) shall not be eligible for settlement pursuant to Sections 3.3A.4 and 3.3A.5. Examples of settlements prohibited pursuant to this Section 3.3A.6(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint, provided that, the foregoing notwithstanding, settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.7 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted. PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. An Economic Load Response Participant's daily settlement will be denied by PJM based on the following criteria:

1) Submission of settlement for self schedule energy in the Real-time Energy Market where only some of the self scheduled hours have been included in the daily settlement submission; or

2) Daily settlement with an estimated value less than Five U.S. Dollars ($5.00); or

3) Daily settlement has a significant number of uneconomic hours *where the Locational Marginal Price is less than or equal to the generation plus the transmission portion of an end-use customer's retail rate or price*.

vi. The electric distribution company and the Load Serving Entity may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, retail rate, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.7. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or busses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

PJMSettlement on behalf of PJM shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy market in the Day-ahead Energy Market at the Day-ahead Congestion prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt busses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt busses is greater than the difference in Locational Marginal Prices between such delivery and receipt busses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection’s determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of the busses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial

Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owner with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.

5.5 Distribution of Total Transmission Loss Charges.

The total Transmission Loss Charges accumulated by PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to section 5.2.2(e) and the award of Financial Transmission Rights pursuant to section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction.

An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly, Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 PM (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual FTR auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term FTR auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term FTR auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term FTR auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of three rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 3 months after the first round, and the third round shall be conducted approximately 3 months after the second round. In each round 1/3 of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three business days ending at 5:00 p.m. on the last day. PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five business days after the close of the bidding period for each round. If the Office of the Interconnection discovers an error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of prices for that auction. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction.

Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

(i) The periods covered by long-term Financial Transmission Rights auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.

(ii) On-Peak, off-peak and 24-hour Financial Transmission Rights obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights Auction. Eligible receipt and delivery points in long-term Financial Transmission Rights Auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Financial Transmission Rights auctions conducted to liquidate a defaulting Member's Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in Section 7.3.9 herein and in accordance with standards and procedures set forth in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Rights sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offeror or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period,

market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.5of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any

offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.3.9 Liquidation of Financial Transmission Rights in the Event of Member Default.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the PJM Operating Agreement or PJM Tariff, the Office of the Interconnection shall, as soon as practicable after such default is declared, initiate the following procedures to close out and liquidate the Financial Transmission Rights of a Member:

a) The Office of the Interconnection shall close out the defaulting Member's positions as of the date of its default, by unilaterally accelerating and terminating all forward Financial Transmission Rights positions.

b) The Office of the Interconnection shall post on its website all salient information relating to the closed out portfolio of Financial Transmission Rights.

c) All current planning period Financial Transmission Right positions within the defaulting Members' Financial Transmission Right portfolio will be offered for sale in the next available monthly balance of planning period Financial Transmission Rights auction at an offer price designed to maximize the likelihood of liquidation of those positions.

d) Financial Transmission Rights positions that do not settle until the next or subsequent planning period will be offered into the next available Financial Transmission Rights auction (taking into account timing constraints and the need for an orderly liquidation) where, based on the Office of Interconnection's commercially reasonable expectation, such positions would be expected to clear. In the event that the next scheduled Financial Transmission Rights

auction is more than two (2) months subsequent to the date that the Office of the Interconnection declares a Member in default, a specially scheduled Financial Transmission Rights auction may be conducted by the Office of the Interconnection. The entire portfolio of the defaulting Member's Financial Transmission Rights will be offered for sale at an offer price designed to maximize the likelihood of liquidation of those positions.

e) The Financial Transmission Right positions comprising the defaulting Member's portfolio that are liquidated in a Financial Transmission Rights auction should avoid setting the price in the auction at the bid prices with which they were initially submitted. In the event that any of the closed out Financial Transmission Rights would set price based on the auction's preliminary solution, then only one-half of each Financial Transmission Rights position will be offered for sale and the auction will be re-executed. In the event that any Financial Transmission Rights position that has been closed out once again sets price, then all Financial Transmission Rights scheduled to be liquidated will be removed from the affected auction and the auction will be re-executed excluding the closed out Financial Transmission Right positions. Financial Transmission Right positions that are not liquidated will then be offered in the next available auction or specially scheduled auction, as appropriate.

f) The liquidation of the defaulting Members' Financial Transmission Rights portfolio pursuant to the foregoing procedures shall result in a final liquidated settlement amount. The final liquidated settlement amount will be included in calculating a Default Allocation Assessment as described in Section 15.1.2A(I) of the PJM Operating Agreement. If the Office of the Interconnection is unable to close out and liquidate a Financial Transmission Rights position under the foregoing procedures, the close out shall be deemed void and the defaulting Member shall remain liable for the full final value of its default, such full final value being realized at the normal time for performance of the Financial Transmission Rights position.

In all other respects, Financial Transmission Rights terminated pursuant to this section shall be liquidated pursuant to the appropriate provisions and procedures set forth in the PJM Manuals.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

(i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;

(ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;

(iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

(i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal

to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone.

Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f)

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points.

A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of the stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service Request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service Request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of Residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligations in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

PJM EMERGENCY LOAD RESPONSE PROGRAM

Emergency Load Response Program

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. As used in the Emergency Load Response Program, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program:

- Full Program Option

  Participants in the Full Program Option receive an energy payment for load reductions during an emergency event pursuant to the Reliability Assurance Agreement, as applicable.

- Energy Only Option

  Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

Participant Qualifications

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Members or Special Members may participate in the Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response provisions herein, including, but not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C***. However, for special members the $5,000 annual membership fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

Special Members are limited to be PJM market sellers;
Voting privileges and sector designation are waived;
Thirty day notice for waiting period is waived;
Requirement for 24/7 control center coverage is waived;
No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

Be capable of reducing at least 100 kW of load
Be capable of receiving PJM notification to participate during emergency conditions.

Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Participant must meter reductions in demand by using either of the following two methods:

a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or

b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

a) Metering equipment used for retail electric service;

b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or

c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com)for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals.Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, Participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than eleven business days prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, given that the electric distribution company and load serving entity must comply with a ten business day review period. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection with ten or fewer business days remaining prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, then the registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration prior to the registration deadline. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection. The following general steps will be followed:

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

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An 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) an end-use customer's participation in PJM's Emergency Load Response Program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after June 1 of the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

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

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

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the 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 Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer's participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements, the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency 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.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program, or notifies the requesting participant and appropriate Load Serving Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance

with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Emergency Load Response Registrations in Effect as of August 28, 2009

All existing Emergency Load Response Participants' registrations submitted to PJM prior to 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")) for Load Management participation in the 2009/2010 Delivery Year will remain effective for that Delivery Year.

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price of a Full Program Option participant that reduces load may set the real time Locational Marginal Price ("LMP") provided that the participant's load reductions are needed to meet demand in the PJM Region. The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the Energy Only Option participant's resource satisfies PJM's telemetry requirements.

Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for the hour prior to the event, as well as every hour during the event. These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option participants shall be the amount PJM dispatches up to the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Reporting

Actual load reductions of Energy Only Option emergency resources will be added back for the purpose of peak load calculations for capacity.

Actual load reductions of Full Program Option and Capacity Only resources that have been registered as Emergency Load Response resources and/or Economic Load Response resources, and which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity. Capacity Only resources are Full Program Option resources that do not receive an energy payment for load reductions during an emergency event. Actual load reductions used for the purpose of calculating peak load for capacity, however, shall not exceed the quantity of kW committed and registered as Full Program Option or Capacity Only resources.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.3 of PJM Emergency Load Response Program, 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 Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

Non-hourly metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response Program that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response Participant aggregations shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. Energy settlement will be based on each individual customer's load reductions pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and

v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

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

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

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

2.21 Demand Resource Factor

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

2.22 Demand Resource Provider

“Demand Resource Provider” shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Demand Resource.

2.23 EFORd

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

2.24 Energy Efficiency Resource

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

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

“Final Zonal ILR Price” shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 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.

2.28 Forecast Pool Requirement

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

2.29 Forecast RTO ILR Obligation

“Forecast RTO ILR Obligation” shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced

Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

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

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.37 Load Serving Entity (LSE)

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

2.38 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 Schedule 10.1 of the Reliability Assurance Agreement.

2.39 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.

2.40 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.

2.41 Locational Reliability Charge

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

2.41A 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.

2.41B Locational UCAP Seller

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

2.41C 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 section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.42 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, as defined in Section 5.

2.43 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.

2.43A 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.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity 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 ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be dispatched independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be dispatched for such block.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

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

2.50 Planned External Generation Capacity Resource

“Planned External Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

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

2.51 Planning Period

“Planning Period” shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

“PJM Region” shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

“PJM Region Installed Reserve Margin” shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

“PJM Region Peak Load Forecast” shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

“Projected PJM Market Revenues” shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

“Qualifying Transmission Upgrade” shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the

Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 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.

2.61A Scheduled Incremental Auctions

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

2.62 Second Incremental Auction

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

2.63 Sell Offer

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

2.64 [Reserved for Future Use]

2.65 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.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, 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.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (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.

2.66 Third Incremental Auction

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

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

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

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B 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.

2.69C 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.

2.70 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 Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining ILR Forecasts for Delivery Years through May 31, 2012;

d) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

e) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

f) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

g) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

h) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

i) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment, Attachment M, Attachment M - Appendix, the Operating Agreement, and the Reliability Assurance Agreement, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, or Reliability Backstop Auction shall be deemed confidential information for purposes of Section 18.17 of the Operating Agreement, Attachment M and Attachment M - Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, 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 Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its eRPM tools. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, 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 Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions as defined in, and pursuant to the rules set forth in, section 5.3A of this Attachment DD, which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such 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 Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its eRPM tools. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

5.1 Introduction

In accordance with the Reliability Assurance Agreement, each Load Serving Entity is obligated to pay a Locational Reliability Charge for each Zone in which it serves load based on the Daily Unforced Capacity Obligation of its loads in such Zone. An LSE may offset the Locational Reliability charge for a Delivery Year, in whole or in part, by: (a) Self-Supply of Capacity Resources in the Base Residual Auction or an Incremental Auction; (b) offering and clearing Capacity Resources in the Base Residual Auction or an Incremental Auction (but only to the extent of the additional resources committed to meet Unforced Capacity Obligations through such Incremental Auction); (c) obtaining certification of load reduction capability as ILR three months prior to the start of the Delivery Year (to the extent permitted hereunder); (d) receiving payments from Capacity Transfer Rights; or (e) offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.3 Commitment of Contractually Purchased Capacity Resources

A Load Serving Entity that has purchased the right to the capacity output of a generation resource and desires to commit such right as a Capacity Resource for a Delivery Year shall be considered a Capacity Market Seller. Such an LSE must submit a Sell Offer in the Base Residual Auction for such Delivery Year, in accordance with the procedure and time schedule set forth in the PJM Manuals. In such Sell Offer, the Capacity Resource offered by the LSE may be submitted as Self-Supply or with an offer price. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction for the purposes set forth in section 2.34. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional

Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, and (2) the Locational Price Adder, if any in such LDA, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily UnforcedCapacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

a. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

b. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

c. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: 1) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or 2) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.

If the Sell Offer is submitted consistent with the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

(ii) in the subsequent two BRAs, if the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA. If the Resource does not clear, it shall be deemed resubmitted at the highest price per MW at which the Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and it shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer that is entitled to compensation for such first year pursuant to section 5.14(b) of this Attachment. The Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect such resubmission. In such case, the Resource submitted under this provision shall be paid for the entire committed quantity the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer Price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; and 3) an adjustment, if required, to account for Resource Make-Whole Payments, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal (1) the sum, for all auctions previously conducted for such Delivery Year, of the Resource Clearing Price for each auction times the Unforced Capacity cleared for such auction (excluding any Unforced Capacity cleared as replacement capacity), divided by (2) the sum of the Unforced Capacity cleared in all such auctions (excluding any Unforced Capacity cleared as replacement capacity), plus an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based, real levelized (year one) Cost of New Entry, net of energy and ancillary service revenues. Other than the levelization approach, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. Until changed, the Net Asset Class Cost of New Entry for a combustion turbine generator shall be $ 96,485MW-year, and the Net Asset Class Cost of New Entry for a combined cycle generator shall be $ 117,035/MW-year. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) base load resources, such as nuclear, coal and Integrated Gasification Combined Cycle, that require a period for development greater than three years; (ii) any facility associated with the production of hydroelectric power; (iii) any upgrade or addition to an existing Generation Capacity Resource; or (iv) any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

(2) Any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, in any LDA for which a separate VRR Curve has been established, and that meets each of the following criteria, shall be subject to the provisions of subsection (3) hereof,

unless the Capacity Market Seller obtains a determination from FERC prior to such Base Residual Auction that such Sell Offer is consistent with the real levelized (year one) competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets):

i. Sell Offer affects the Clearing Price;

ii. Sell Offer is less than 80 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as stated in subsection (h)(1) above; and

iii. The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts. A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply. An "actual retail load obligation" shall mean the LSE's combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement. A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the BRA, under contract for the Delivery Year.

(3) The Office of the Interconnection shall perform a sensitivity analysis on any Base Residual Auction that included Sell Offers meeting the criteria of Section 5.14(h)(2), for which the Capacity Market Seller has not obtained a prior favorable determination from FERC as described in subsection (2) hereof. Such analysis shall re-calculate the clearing price for the Base Residual Auction employing in place of each actual Sell Offer meeting the criteria a substitute Sell Offer equal to 90 percent of the applicable estimated cost determined in accordance with Section 5.14(h)(1) above, or, if there is no applicable estimated cost, equal to 80 percent of the then-applicable Net CONE. If the resulting difference in price between the new clearing price and the initial clearing price differs by an amount greater than the greater of 20 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 15,000 megawatts; or the greater of 25 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 5,000 and less than 15,000 megawatts; or the greater of 30 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement of less than 5,000 megawatts; then the Office of the interconnection shall discard the results of the Base Residual Auction and determine a replacement clearing price and the identity of the accepted Capacity Resources using the procedure set forth in section 5.14(h)(4) below.

(4) Including all of the Sell Offers in a single Base Residual Auction that meet the criteria of 5.14(h)(3) above, PJM shall first calculate the replacement clearing price and the

total quantity of Capacity Resources needed for the LDA. PJM shall then accept Sell Offers to provide Capacity Resources in accordance with the following priority and criteria for allocation: (i) first, all Sell Offers in their entirety designated as self-supply committed regardless of price; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price, subject to the optimization principles set forth in Section 5.14.

(5) Notwithstanding the foregoing, this provision shall terminate when there exists a positive net demand for new resources, as defined in Section 5.10(a)(iv)(B) of this Attachment, calculated over a period of consecutive Delivery Years beginning with the first Delivery Year for which this Attachment is effective and concluding with the last Delivery Year preceding such calculation, in an area comprised of the Unconstrained LDA Group (as defined in section 6.3) in existence during such first Delivery Year. Notwithstanding the foregoing, the Office of the Interconnection shall reinstate the provisions of this section, solely under conditions in which a constrained LDA has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.

(i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained

LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of installed capacity, applicable to price-quantity offers within the Base Offer Segment for an existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the

Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from a Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in the Base Residual Auction or Incremental Auction for adjustment of committed capacity for the first Delivery Year for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources shall be treated as Existing Generation Capacity Resources in the auctions for any subsequent Delivery Year; provided, however, that such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all Unforced Capacity of all existing Generation Capacity Resources located in the PJM Region shall be offered (which may include submission as Self-Supply) in the Base Residual Auction for each Delivery Year, where Unforced Capacity is determined using an EFORd less than or equal to the greater of (i) the annual average EFORd for the five consecutive years ending on the September 30 that last precedes the submission of such offers or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(b) For each existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the EFORd applicable to each resource. The Generation Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed EFORd, and attempt to reach agreement with the Market Monitoring Unit on the level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.C of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of the EFORd, the Office of the Interconnection shall make its own determination of the level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) Existing generation resources in the PJM Region capable of qualifying as a Generation Capacity Resource may not avoid the rule in subsection (a) by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource, excepting only generation resources that, as shown by appropriate documentation: (i) are reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) have a financially and physically firm commitment to an external sale of its capacity, or (iii) were interconnected to the Transmission System as Energy Resources and not subsequently converted to a Capacity Resource. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff;

B. Significant physical operational restrictions that cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff; or,

C. The Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource.

(h) Any existing generation resource located in the PJM Region that is not offered into the Base Residual Auction for a Delivery Year, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

(i) To avoid application of subsection (j), any existing Generation Capacity Resource located in the PJM Region that is offered into the Base Residual Auction for a Delivery Year, but that does not clear in such auction, shall be offered in the First, Second, and Third Incremental Auctions (and any Conditional Incremental Auction) for such Delivery Year, unless such Generation Capacity Resource, as shown by appropriate documentation, (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

(j) Any existing Generation Capacity Resource located in the PJM Region that is offered into the Base Residual Auction for a particular Delivery Year, does not clear in such auction, is not offered into the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, and does not meet any of the exceptions stated in subsection (g): (i) may not participate in any subsequent auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year; (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year, and (iv) may be subject to further action by the Market Monitoring Unit under Attachment M and Attachment M - Appendix.

(k) In addition to the remedies set forth in subsections (g), (h), (i), and (j), if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources into an auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the

Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource

Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

Table title: **Maximum Avoidable Cost Rates by Technology Class**

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate. The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(c) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-

Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

  - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

  - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

  - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

  - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

  - **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

  - **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

  - **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 16 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as “at-risk” at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

16. RELIABILITY BACKSTOP

16.1. Purpose

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by: (a) lack of sufficient capacity committed through the Reliability Pricing Model Auctions; or (b) near-term transmission deliverability violations identified after the Base Residual Auction is conducted. These backstop mechanisms are intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The backstop mechanisms are based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources through Self-Supply or the Reliability Pricing Model Auctions.

16.2 Investigation of Capacity Shortfall

If the total Unforced Capacity of Capacity Resources committed for a Delivery Year following the Base Residual Auction equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection shall investigate the cause for the shortage, and recommend corrective action, including, without limitation, adjusting the Cost of New Entry to the extent determined necessary by such investigation, or addressing other barriers to entry identified by such investigation. No Reliability Backstop Auction will be conducted to address such a shortfall unless it occurs in the Base Residual Auctions for three consecutive Delivery Years.

16.3 Triggering Conditions

a) Either of the following two conditions will trigger reliability backstop measures provided in this section, as described below:

i) If the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years, equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection will declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

ii) If the total Unforced Capacity of all Base Load Generation Resources committed in a Base Residual Auction for a Delivery Year is less than the forecasted minimum hourly load calculated by the Office of the Interconnection for such Delivery Year, the Office of the Interconnection will investigate the cause of shortfall. If such a shortfall occurs in the Base Residual Auctions for three consecutive Delivery Years, the Office of the Interconnection shall declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

b) In addition to the foregoing events that trigger reliability backstop measures, if a near-term, i.e., later in time than the conduct of the Base Residual Auction for a Delivery Year, transmission criteria violation caused by an announced generation resource deactivation is identified by the regional transmission reliability planning analysis performed by the Office of the Interconnection in accordance with Part V of this Tariff, the Office of the Interconnection will identify the necessary transmission upgrade. In accordance with such rules, such generation resource may remain in service until the transmission upgrade is installed. No Reliability Backstop Auction will be conducted.

16.4. Reliability Backstop Auction

a) Scope of Auction

The Office of the Interconnection shall conduct each Reliability Backstop Auction to commit additional Generation Capacity Resources, or in the case of an auction triggered by section 16.3(a)(ii), additional Base Load Generation Resources to the PJM Region to resolve the system-wide reliability criteria violation that triggered the need for such auction. Capacity Resources committed in a Reliability Backstop Auction for a Delivery Year shall not include any Planned Generation Capacity Resources previously committed in the Base Residual Auction for such Delivery Year. The Reliability Backstop Auction shall obtain commitments of additional Generation Capacity Resources (or, as applicable, additional Base Load Generation Resources) for a term of up to fifteen (15) Delivery Years. If a Reliability Backstop Auction is required, the offer period for such auction shall commence, subject to FERC approval as specified above, no later than four months after the Base Residual Auction in which the third consecutive Capacity Resource shortfall occurs. Upon verification and notification by the PJM Board of Managers that a Reliability Backstop Auction is required, the Office of the Interconnection shall post notification that a Reliability Backstop Auction is to be held. Upon such notification, the offer period shall commence, and shall remain open for six (6) months. PJMSettlement shall be the Counterparty to the capacity transaction resulting from committed Capacity Resources clearing the Reliability Backstop Auction.

b) Sell Offers

Each Sell Offer shall specify the following information, as further specified in the PJM Manuals:

- the minimum price in $/MW-day required by the Capacity Market Seller to provide additional Unforced Capacity from a Generation Capacity Resource (or from a Base Load Generation Resource, in the case of an auction triggered by section 16.3(a)(ii));

- the megawatts of Unforced Capacity to be provided by such resource;

- the specific location of the proposed plant;

- all information required from a Generation Interconnection Customer by Part IV of this Tariff and the PJM Manuals;

- general plant technical specifications, as specified in the PJM Manuals;
- the term of cost recovery (“Backstop Period”) requested, not to exceed 15 years; and
- the first full Delivery Year for which such resource shall be available, which shall also be the first year of the Backstop Period.

Each Generation Capacity Resource (or Base Load Generation Resource) accepted in a Reliability Backstop Auction shall comply with the procedures for new generation interconnection in Part IV of this Tariff, and each such resource shall be responsible for satisfying all capability and deliverability requirements for Capacity Resources, pursuant to the Reliability Assurance Agreement.

c) Submission of Sell Offers

The Sell Offer period shall begin at 00:01 Eastern Prevailing Time on the date specified by the Office of the Interconnection in the notification posting and shall end at 23:59 Eastern Prevailing Time six calendar months after such date. Sell offers shall be submitted during such period in writing to the Office of the Interconnection, and shall conform to the submission procedures as specified in the PJM Manuals. The Office of the Interconnection shall confirm in writing the receipt of each Sell Offer, within two weeks after receipt of each such offer.

d) Posting of Information by the Office of the Interconnection

Upon notification by the PJM Board of Managers that a Reliability Backstop Auction will be conducted, the Office of the Interconnection shall post the following information:

- System condition that necessitates a Reliability Backstop Auction;
- Megawatt quantity of Unforced Capacity required from additional Generation Capacity Resources, or from additional Base Load Generation Resources;
- Date by which the resources must be capable of delivering Unforced Capacity;
- Any other required specifications for the additional Unforced Capacity sought through such auction.

e) Conduct of the Reliability Backstop Auction

i) Auction Clearing Procedure

The Reliability Backstop Auction shall select the Sell Offer or combination of Sell Offers that that satisfies the requirements posted by the Office of the Interconnection at the lowest offer price(s). If more than one Sell Offer must be selected to satisfy the specified requirements, the

Sell Offers shall be selected in rank order from lowest offer price to highest offer price until the requirement is satisfied. In the event two or more Sell Offers specify the same offer price, and fewer than all of such offers are needed to satisfy the specified requirements, the Office of the Interconnection shall select the Sell Offer(s) proposing Generation Capacity Resource(s), or, as applicable, Base Load Generation Resource(s) that will best satisfy overall reliability requirements for the PJM Region, as determined by the Office of the Interconnection using transmission reliability analysis.

ii) Market Settlement

Pursuant to the agreement specified below, each Capacity Market Seller submitting a Sell Offer that is accepted in a Reliability Backstop Auction shall be paid by PJMSettlement the offer price in such Sell Offer for each MW-day in the Backstop Period, less any payments the Capacity Market Seller is entitled to receive pursuant to section 5 of this Attachment as a result of Sell Offers submitted with respect to such Generation Capacity Resource in any Base Residual Auction or Incremental Auction, including, without limitation, payments of Capacity Resource Clearing Prices (including for Self-Supply) and Resource Make-Whole Payments; and less any payments the Capacity Market Seller is entitled to receive for energy or ancillary services pursuant to Schedule 1 of the Operating Agreement with respect to services provided by such resource, net of the Variable Operations and Maintenance costs of such resource, as determined in accordance with the PJM Manuals.

PJM shall recover the costs of any such payments to Capacity Market Sellers for such resources through a charge, in addition to the Locational Reliability Charge, assessed on all LSEs in the PJM Region, pro rata based on each such LSE's Daily Unforced Capacity Obligations in all LDAs in which such LSE serves load. PJMSettlement shall be the Counterparty to the LSE's obligation to pay, and payment of, such charges.

iii) Standard Contract Provisions

PJMSettlement, will enter into an agreement with each Capacity Market Seller that submitted an accepted Sell Offer in any Reliability Backstop Auction providing for the payments specified above. Such agreement shall include the provisions and address the standards set forth in Section 16.4(b), and shall include such other terms and conditions as are customary in the industry, as specified in the PJM Manuals.

f) FERC Approval

Any such agreement shall provide that it shall be filed with FERC as a rate schedule pursuant to section 205 of the Federal Power Act, and that the effectiveness of such agreement shall be conditioned on receipt of FERC acceptance or approval of such agreement.

16.5 Must Offer into Base Residual Auction

All Capacity Market Sellers submitting a Sell Offer that is selected in a Reliability Backstop Auction must offer all Unforced Capacity of the Generation Capacity Resource underlying such

Sell Offer into the Base Residual Auctions conducted subsequent to the Reliability Backstop Auction for all Delivery Years in the Backstop Period. The Market Seller shall offer the Unforced Capacity of such resources into each such auction at zero price, and shall receive the Capacity Resource Clearing Price as determined in each such auction.

16.6 Reliability Backstop Resource Deficiency Charges

(a) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that is not able to deliver in a Delivery Year all megawatts of Unforced Capacity specified in the selected Sell Offer, shall not receive any payments that such Capacity Market Seller otherwise would have been eligible to receive for such Delivery Year pursuant to the Reliability Backstop Auction.

(b) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that fails to deliver all megawatts of Unforced Capacity specified in the selected Sell Offer at any time during the Backstop Period specified in such Sell Offer must refund all payments received by such Market Seller pursuant to section 16.4(b).

PJM Operating Agreement Revisions

(Non-Redlined Version)

Definitions C - D

1.6 Capacity Resource.

"Capacity Resource" have the meaning provided in the Reliability Assurance Agreement.

1.6A Consolidated Transmission Owners Agreement.

"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.

1.7 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 the applicable regional reliability council of NERC;

(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.

1.7.01 Control Zone.

"Control Zone" shall mean any of the ECAR Control Zone(s), MAAC Control Zone, or MAIN Control Zone(s), or the VACAR Control Zone.

1.7.01a Counterparty.

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

"Default Allocation Assessment" shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

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

1.7A [Reserved].

1.7B [Reserved].

Definitions O - P

1.27 Office of the Interconnection.

"Office of the Interconnection" shall mean the LLC.

1.28 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 a Control Zone, as specified in the PJM Manuals.

1.29 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.

1.30 Other Supplier.

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillatry 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.

1.31 PJM Board.

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to this Agreement.

1.31A [Reserved].

1.32 PJM Control Area.

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

1.33 PJM Dispute Resolution Procedures.

"PJM Dispute Resolution Procedures" shall mean the procedures for the resolution of disputes set forth in Schedule 5 of this Agreement.

1.34 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 Schedule 1 to this Agreement.

1.35 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.

1.35.01 PJM Market Monitor.

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

1.35A PJM Region.

"PJM Region" shall mean the aggregate of the MAAC Control Zone, the PJM West Region, and VACAR Control Zone.

1.35B PJM South Region.

"PJM South Region" shall mean the VACAR Control Zone.

1.35C PJMSettlement.

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

1.36 PJM Tariff.

"PJM Tariff" shall mean the PJM Open Access Transmission Tariff providing transmission service within the PJM Region, including any schedules, appendices, or exhibits attached thereto, as in effect from time to time.

1.36A [Reserved.]

1.36B PJM West Region.

"PJM West Region" shall mean the aggregate of the ECAR Control Zone(s) and MAIN Control Zone(s).

1.37 Planning Period.

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

1.38 President.

"President" shall have the meaning specified in Section 9.2.

7.7 Duties and Responsibilities of the PJM Board.

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

i) As its primary responsibility, ensure that the President, the other officers of the LLC, and Office of the Interconnection perform the duties and responsibilities set forth in this Agreement, including but not limited to those set forth in Sections 9.2 through 9.4 and Section 10.4 in a manner consistent with (A) the safe and reliable operation of the PJM Region, (B) the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and (C) the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Region;

ii) Select the Officers of the LLC;

iii) Adopt budgets for the LLC;

iv) Approve the Regional Transmission Expansion Plan in accordance with the provisions of the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of this Agreement;

v) On its own initiative or at the request of a User Group as specified herein, submit to the Members Committee such proposed amendments to this Agreement or any Schedule hereto, or a proposed new Schedule, as it may deem appropriate;

vi) Petition FERC to modify any provision of this Agreement or any Schedule or practice hereunder that the PJM Board believes to be unjust, unreasonable, or unduly discriminatory under section 206 of the Federal Power Act, subject to the right of any Member or the Members to intervene in any resulting proceedings;

vii) Review for consistency with the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region any change to rate design or to non-rate terms and conditions proposed by Transmission Owners for filing under section 205 of the Federal Power Act;

viii) If and to the extent it shall deem appropriate, intervene in any proceeding at FERC initiated by the Members in accordance with Section 11.5(b), and participate in other state and federal regulatory proceedings relating to the interests of the LLC;

ix) Review, in accordance with Section 15.1.3, determinations of the Office of the Interconnection with respect to events of default;

x) Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to PJMSettlement and the Office of the Interconnection, including interest thereon, as to which a Member is in default;

xi) Establish reasonable sanctions for failure of a Member to comply with its obligations under this Agreement;

xii) Direct the Office of the Interconnection on behalf of the LLC and PJMSettlement to take appropriate legal or regulatory action against a Member (A) to recover any unpaid amounts due from the Member to the Office of the Interconnection under this Agreement and to make whole any Members subject to an assessment as a result of such unpaid amount, or (B) as may otherwise be necessary to enforce the obligations of this Agreement;

xiii) [Reserved.]

xiv) [Reserved.]

xv) Solicit the views of Members on, and commission from time to time as it shall deem appropriate independent reviews of, (a) the performance of the PJM Interchange Energy Market, (b) compliance by Market Participants with the rules and requirements of the PJM Interchange Energy Market, and (c) the performance of the Office of the Interconnection under performance criteria proposed by the Members Committee and approved by the PJM Board; and

xvi) Terminate a Member as may be appropriate under the terms of this Agreement.

11.6 Membership Requirements.

(a) To qualify as a Member, an entity shall:

i) Be a Transmission Owner a Generation Owner, an Other Supplier, an Electric Distributor, or an End-Use Customer; and

ii) Accept the obligations set forth in this Agreement.

(b) Certain Members that are Load Serving Entities are parties to the Reliability Assurance Agreement. Upon becoming a Member, any entity that is a Load Serving Entity in the PJM Region and that wishes to become a Market Buyer shall also simultaneously execute the Reliability Assurance Agreement

(c) An entity that wishes to become a party to this Agreement shall apply, in writing, to the President setting forth its request, its qualifications for membership, its agreement to supply data as specified in this Agreement, its agreement to pay all costs and expenses in accordance with Schedule 3, and providing all information specified pursuant to the Schedules to this Agreement for entities that wish to become Market Participants. Any such application that meets all applicable requirements shall be approved by the President within sixty (60) days.

(d) Nothing in this Section 11 is intended to remove, in any respect, the choice of participation by other utility companies or organizations in the operation of the PJM Region through inclusion in the System of a Member.

(e) An entity whose application is accepted by the President pursuant to Section 11.6(c) shall execute a supplement to this Agreement in substantially the form prescribed in Schedule 4, which supplement shall be countersigned by the President. The entity shall become a Member effective on the date the supplement is countersigned by the President.

(f) Entities whose applications contemplate expansion or rearrangement of the PJM Region may become Members promptly as described in Sections 11.6(c) and 11.6(e) above, but the integration of the applicant's system into all of the operation and accounting provisions of this Agreement and the Reliability Assurance Agreement, shall occur only after completion of all required installations and modifications of metering, communications, computer programming, and other necessary and appropriate facilities and procedures, as determined by the Office of the Interconnection. The Office of the Interconnection shall notify the other Members when such integration has occurred.

(g) Entities that become Members will be listed in Schedule 12 of this Agreement.

(h) In accordance with the MAAC Agreement, a Member serving load in the MAAC Control Zone shall be a member of MAAC and any other Member may be a member of MAAC.

(i) In accordance with this Agreement, Members agree that PJMSettlement shall be the Counterparty with respect to certain transactions under the PJM Tariff and this Agreement.

14B.1 Billing Procedure:

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

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

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

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

14B.2 Payments:

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

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

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

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

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

14B.3 Interest on Unpaid Balances:

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by PJMSettlement.

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

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

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

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

(i) A Member shall be entitled to payment from PJMSettlement during the settlement period if, and only if, during the settlement period there is no amount in default due and payable by that Member to PJMSettlement with respect to transactions for which PJMSettlement is a Counterparty and not paid or recovered and so long as an amount in default, or any part of it, remains owing to PJMSettlement, that Member will not request, demand or claim to be entitled to payment by PJMSettlement.

(ii) Subject to section 15, a defaulting Member shall be entitled to payment from PJMSettlement with respect to transactions for which PJMSettlement is the Counterparty, if, and only if, all amounts, liabilities and other obligations due, owing, incurred or payable by that defaulting Member to PJMSettlement or the LLC, whether those liabilities or obligations are actual or contingent, present or future, joint or several (including, without limitation, all interest (after as well as before judgment) and expenses) have been paid or recovered and until that time the defaulting Member will not request, demand or claim to be entitled to payment by PJMSettlement or the LLC.

(d) **Set-off.**

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

(ii) If in respect of any non-paying Member there is more than one amount in default, then any amount due and payable from PJMSettlement shall be set off against the amounts in default in the order in which they originally became due and payable.

(e) **Liability of PJMSettlement.**

(i) The liability of PJMSettlement to make payments during the settlement period shall be limited so that the aggregate of such payments does not exceed the aggregate amount of payments that has been paid to or recovered by PJMSettlement, from Members (including by way of realization of financial security) in respect of that settlement period.

(ii) Where in relation to any settlement period, the aggregate amount that PJMSettlement pays to Members with respect to transactions for which PJMSettlement is the Counterparty is less than the amount to which those Members, but for the operation of section 14B(e)(i), would have been entitled: if and to the extent that, after the required time during the settlement period, PJMSettlement or the LLC is paid and recovers (including collection of such amount through Default Allocation Assessments) amounts from any Member, PJMSettlement shall to the extent of such receipts make payments (to certain Members) in accordance with the provisions of section 15.2.1.

15.1 Failure to Meet Obligations.

15.1.1 Termination of Market Buyer Rights.

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

15.1.2 Termination of Market Seller Rights.

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

15.1.2A Close Out and Liquidation of Member Financial Transmission Rights

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

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

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

15.1.3 Payment of Bills.

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

15.1.4 Breach Notification and Remedy

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

15.1.5 Default Notification and Remedy

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

i) A defaulting Market Participant shall be precluded from buying or selling in the PJM Interchange Energy Market, the PJM Capacity Credit Market, or any other market operated by PJM until the default is remedied as set forth above;

ii) A defaulting Member shall not be entitled to participate in the activities of any committee or other body established by the Members Committee or the Office of the Interconnection; and

iii) A defaulting Member shall not be entitled to vote on the Members Committee or any other committee or other body established pursuant to this Agreement.

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

15.1.6 Reinstatement of Member Following Default and Remedy

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

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

a) Loss of stakeholder privileges, including voting privileges, for 12 months following such default; and

b) Loss of the allowance of unsecured credit for 12 months following such default

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

a) PJMSettlement shall close out and liquidate all of the terminated Member's current and forward positions in accordance with the provisions of this Agreement; and

b) A Member terminated in accordance with these provisions shall be precluded from seeking future membership under this Agreement;

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

a) that it has otherwise consistently complied with its obligations under this Agreement and the PJM Tariff; and

b) the failure to comply was not material; and

c) the failure to comply was due in large part to conditions that were not in the common course of business.

15.5 No Implied Waiver.

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

15.6 Limitation on Claims.

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

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

16.6 Gross Negligence or Willful Misconduct.

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

1.1 Introduction.

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

1.5 Market Sellers.

1.5.1 Qualification.

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

1.5.2 Withdrawal.

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

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

1.5A Economic Load Response Participant.

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

1.5A.1 Qualification.

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

1.5A.2 Special Member.

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

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete the Economic Load Response 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.

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 appropriate electric distribution company or Load Serving Entity 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, and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. An 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A

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

i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity 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, and, if permitted, confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. If the 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 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 electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with section 1.5A hereof, including section 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, electric distribution company or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program 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 Participants' registrations 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 section 1.5A, including section 1.5A.3.

1.5A.4 Metering.

The Curtailment Service Provider is responsible to ensure that the Economic Load Response Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Economic Load Response Participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

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 [Reserved for Future Use]

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 customer or its Curtailment Service Provider or Load Serving Entity 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"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.04 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.07 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

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

(a) A Batch Load Demand Resource may provide Sychronized Reserve or Day-ahead Scheduling Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Demand Resource” pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Day-ahead Scheduling Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Demand Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Demand Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Day-ahead Scheduling Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection’s calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load Demand Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Day-ahead Scheduling Reserves, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Day-ahead Scheduling Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Sychronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Day-ahead Scheduling Reserves to reduce load.

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

Economic Load Response Participants may participate in the Day-ahead and Real-time Energy Markets as dispatchable or self-scheduled resources, provided that Demand Resources that are self-scheduled pursuant to Section 1.5A.9(a) shall not be dispatched by the Office of the Interconnection pursuant to this section.

(a) Self-scheduled Demand Resources shall be subject to the following requirements:

i. An Economic Load Response Participant self-scheduling a Demand Resource shall notify the Office of the Interconnection no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event;

ii. Economic Load Response Participants may self-schedule a Demand Resource intra-hour;

iii. A Notification pursuant to this section may be withdrawn or adjusted downward during the relevant event hour, but not after the event hour;

iv. A Notification submitted pursuant to this section shall include the start and stop times of the event and the amount of the demand reduction;

v. The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the Economic Load Response Participant has provided a Notification.

1.5A.10 Economic Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 500 kW of demand response in the Day-Ahead Scheduling Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to Section 1.5A.1 shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. If all End-Use Customers in an aggregation are not subject to the same generation and transmission charges, the generation and transmission charge for the aggregation shall be the load weighted average of the generation and transmission charges for all End-Use Customers in the aggregation. The Economic Load Response Participant shall provide the load weighted average, the calculation of the load weighted average, and the supporting data to the Load Serving Entity and PJM. For the purposes of this section, the applicable generation and transmission charges are the charges an End-Use Customer would have otherwise paid the Load Serving Entity absent the demand reduction;

v. A single CBL for the aggregation shall be used to determine settlements pursuant to Sections 3.3A.4 and 3.3A.5;

vi. 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 99 kW 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 499 kW of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vii. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource except for the 100 kW minimum load reduction requirement for energy or the 500 kW minimum load reduction requirement for Ancillary Services; and

viii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.6 Office of the Interconnection.

1.6.1 Operation of the PJM Interchange Energy Market.

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

1.6.2 Scope of Services.

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

i) Administer the PJM Interchange Energy Market as part of the PJM Region, including scheduling and dispatching of generation resources, accounting for transactions, maintaining appropriate records, and monitoring the compliance of Market Participants with the provisions of this Agreement, all in accordance with applicable provisions of the Operating Agreement, and the Schedules to this Agreement;

ii) Review and evaluate the qualification of entities to be Market Buyers, Market Sellers, or Economic Load Response Participants under applicable provisions of this Agreement;

iii) Coordinate, in accordance with applicable provisions of this Agreement, the Reliability Assurance Agreement, and the Consolidated Transmission Owners Agreement, maintenance schedules for generation and transmission resources operated as part of the PJM Region;

iv) Provide or coordinate the provision of ancillary services necessary for the operation of the PJM Region or the PJM Interchange Energy Market;

v) Determine and declare that an Emergency is expected to exist, exists, or has ceased to exist, in all or any part of the PJM Region, or in another directly or indirectly interconnected Control Area and serve as a primary point of contact for interested state or federal agencies;

vi) Administer (a) agreements for the transfer of energy in conditions constituting an Emergency in the PJM Region or in an interconnected Control Area, and the mutual provision of other support in such Emergency conditions with other interconnected Control Areas, and (b) purchases of Emergency energy offered by Members from resources that are not Capacity Resources in conditions constituting an Emergency in the PJM Region;

vii) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Reliability Council principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement;

viii) Protect confidential information as specified in this Agreement; and

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

1.6.3 Records and Reports.

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

1.6.4 PJM Manuals.

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

1.6A PJMSettlement

1.6A.1 Scope of Services

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

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

1.7.2 Market Buyers.

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

1.7.2A Economic Load Response Participants.

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

1.7.3 Agents.

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

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (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 active load management, interruption of load, 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.

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

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

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

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

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

1.7.5 Market Operations Center.

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

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

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

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

1.7.7 Pricing.

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

1.7.8 Generating Market Buyer Resources.

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

1.7.9 Delivery to an External Market Buyer.

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

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler 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 eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy 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 eSchedules and Enhanced Energy Schedules 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 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 dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

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

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

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

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

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council 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 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 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 Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

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

1.7.16 Recording.

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

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

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

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

1.7.18 Regulation.

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

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

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned.

(d) A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.

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

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. 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.

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

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

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

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

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC’s rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM’s markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

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

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, 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 Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets 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 eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

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

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

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

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

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

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

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 *M*arket. 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 transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified 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.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 *of the Operating* Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction, amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.5 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post on the PJM Open Access Same-time Information System 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.5 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. 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).

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

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.5 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

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

1.10.4 Capacity Resources.

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

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

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data. If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the load 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 or credited at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing load bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.

(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. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve *Obligation* from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by the External Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulationmarket-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection and that is not committed solely for the purpose of providing Synchronized Reserve: For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Regulation Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Regulation, Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each period the unit operates in condensing and generation mode for one or more contiguous hours.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for each Control Zone of the PJM Region based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such Control Zone pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues 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 Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for

Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = (\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}) \Big/ (\mathbf{UDSLAtime}_{t-1})$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time

3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated *balancing Operating Reserve* charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP *at the resource's bus does not meet or exceed* the *applicable* offer of the resource for at least four-5-minute intervals during one or more discrete *clock* hours *during each* period *the resource operated and produced MWs* during the relevant Operating Day. *If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.*

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone, for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or

Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2A(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services 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 (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 Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule, for demand reductions measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBLdetermined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01, respectively; or 2) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent highest load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. For the purposes of calculating the CBL for weekdays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. NERC holidays;

2. Event day(s), as defined in subsection (a)(i)(3) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

3. Weekdays the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection;

4. Any weekday the event period usage is less than 25% of the average event period usage for the five days.

iii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection;

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. For the purposes of calculating the CBL for Saturdays or Sundays/NERC holidays, the 45-day period shall be extended one day for each of the following days that occur within the relevant period, provided that extensions pursuant to this section shall not exceed 15 days (i.e. 60 days total including the relevant 45-day period):

1. Event day(s), as defined in subsection (b)(i)(1) above, in which the hourly LMP exceeds the annual threshold in at least 4 hours, where the annual threshold will be effective from June 1 through May 31 and will be determined based on the load weighted average PJM real time LMP for the 99th percentile for the calendar year prior to May 31;

2. Saturday or Sundays/NERC holidays where the relevant end-use customer site responds to the dispatch instructions of the Office of the Interconnection.

iii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iv) of this section.

iv. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use costumer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant, Load Serving Entity, electric distribution company, and/or the Office of the Interconnection ("Interested Parties") may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. Any proposal made pursuant to this section shall be provided to all other Interested Parties.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is received by all Interested Parties. If all Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon all Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.4 and 3.3A.5.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used soley to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Weather-Sensitive and Symmetric Additive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or "WSA") or Symmetric Additive Adjustment for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment and Symmetric Additive Adjustment shall be calculated using the following applicable formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer's on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index ("THI") on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

The regression analysis will produce a slope (m), expressed in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer's load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

WSA = [(m x THIEVENT DAY) + b]/[(m x THICBL DAYS) +b]

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the

Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer's location may be used if it can be shown that the temperature at the end-use customer's location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.

- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer's historical, seasonal, on-peak non-coincident peak load.

Symmetric Additive Adjustment

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by PJMSettlement the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) In cases where the demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(d) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer's zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant's zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, PJMSettlement shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer's demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid less an amount equal to the applicable generation and transmission charges. For the purposes of this section, the applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction, and the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(d) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

3.3A.6 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.4 and 3.3A.5 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market.

(b) Demand reductions that do not meet the requirements of Section 3.3A.6(a) shall not be eligible for settlement pursuant to Sections 3.3A.4 and 3.3A.5. Examples of settlements prohibited pursuant to this Section 3.3A.6(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint, provided that, the foregoing notwithstanding, settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.6(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.7 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to 3.3A.4 and 3.3A.5 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.4 and 3.3A.5 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted. PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

   i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

   ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. An Economic Load Response Participant's daily settlement will be denied by PJM based on the following criteria:

1) Submission of settlement for self schedule energy in the Real-time Energy Market where only some of the self scheduled hours have been included in the daily settlement submission; or

2) Daily settlement with an estimated value less than Five U.S. Dollars ($5.00); or

3) Daily settlement has a significant number of uneconomic hours *where the Locational Marginal Price is less than or equal to the generation plus the transmission portion of an end-use customer's retail rate or price*.

vi. The electric distribution company and the Load Serving Entity may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, retail rate, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.7. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

3.4 Transmission Customers.

3.4.1 Transmission Congestion Charges.

Each Transmission Customer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.4.2 Transmission Loss Charges.

Each Transmission Customer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.4.3 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Transmission Customer in accordance with the charges and credits specified in Sections 3.4.1 through 3.4.2 of this Schedule, and showing the net amount to be paid or received by the Transmission Customer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Transmission Customer's internal accounting.

3.5 Other Control Areas.

3.5.1 Energy Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell energy to a Control Area interconnected with the PJM Region as necessary to alleviate or end an Emergency in that interconnected Control Area. Such sales shall be made (i) only to Control Areas that have undertaken a commitment pursuant to a written agreement with the LLC to sell energy on a comparable basis to the PJM Region, and (ii) only to the extent consistent with the maintenance of reliability in the PJM Region. The Office of the Interconnection may decline to make such sales to a Control Area that the Office of the Interconnection determines does not have in place and implement Emergency procedures that are comparable to those followed in the PJM Region. If the Office of the Interconnection sells energy to an interconnected Control Area as necessary to alleviate or end an Emergency in that Control Area, such energy shall be sold at 150% of the Real-time Price at the bus or buses at the border of the PJM Region at which such energy is delivered.

3.5.2 Operating Margin Sales.

To the extent appropriate in accordance with Good Utility Practice, the Office of the Interconnection may sell Operating Margin to an interconnected Control Area as requested to alleviate an operating contingency resulting from the effect of the purchasing Control Area's operations on the dispatch of resources in the PJM Region. Such sales shall be made only to Control Areas that have undertaken a commitment pursuant to a written agreement with the Office of the Interconnection (i) to purchase Operating Margin whenever the purchasing Control Area's operations will affect the dispatch of resources in the PJM Region, and (ii) to sell Operating Margin on a comparable basis to the LLC.

3.5.3 Transmission Congestion.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges as specified in Section 5.1.5 of this Schedule.

3.5.4 Billing.

PJMSettlement on behalf of PJM shall prepare a billing statement each billing cycle for each Control Area to which Emergency energy or Operating Margin was sold, and showing the net amount to be paid by such Control Area. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses in accordance with Section 9.3, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding

Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using Point-to-Point Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of

Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Rights. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of the buses that comprise the Zone multiplied by the percent of annual peak load assigned to each node. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period.

Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.3 Unscheduled Transmission Service (Loop Flow).

(a) When there are agreements between the LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the total Transmission Congestion Charges that are distributed in accordance with Section 5.2.

(b) With respect to payments by the Office of the Interconnection to the New York Power Pool for the installation and operation of phase angle regulating facilities at Ramapo to control or limit unscheduled transmission service (loop flow), each of the following Transmission Owners with revenue requirements under the PJM Tariff shall pay a share of the charges on a transmission revenue requirements ratio share basis: Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc.

7.1 Auctions of Financial Transmission Rights.

Annual, periodic and long-term auctions to allow Market Participants to acquire or sell Financial Transmission Rights shall be conducted by the Office of the Interconnection in accordance with the provisions of this Section. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions; provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfer of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

7.1.1 Auction Period and Scope of Auctions.

(a) The periods covered by auctions shall be: (1) the one-year period beginning the month after the final round of an annual auction; (2) any single calendar month period remaining in the Planning Period that is within the three, or less, month period immediately following the month that the monthly auction is conducted; (3) any Planning Period Quarter remaining in the Planning Period following the month that the monthly auction is conducted; and (4) the Planning Period Balance. In addition to the period defined in (2) of this subsection, only one of the periods defined in (3) or (4) of this subsection will be included in the monthly auction clearing until the Office of the Interconnection determines that both of the periods defined in (3) and (4) can be solved simultaneously in the same monthly auction process within the timeframe specified in Section 7.3.7. With the exception of FTRs allocated pursuant to Section 5.2.2 (e) of this Schedule and the Financial Transmission Rights awarded as a result of the exercise of the conversion option pursuant to Section 7.1.1(b) of this Schedule, in the annual auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale the entire Financial Transmission Rights capability for the year in four rounds with 25 percent of the capability offered in each round. In the monthly auction, the Office of the Interconnection, on behalf of PJMSettlement, shall offer for sale in the auction any remaining Financial Transmission Rights capability for the months remaining in the Planning Period after taking into account all of the Financial Transmission Rights already outstanding at the time of the auction. In addition, any holder of a Financial Transmission Right for the period covered by an auction may offer such Financial Transmission Right for sale in such auction. On-Peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auctions. FTRs will be offered as Financial Transmission Right Obligations and Financial Transmission Right Options, provided that such Financial Transmission Right Obligations and Financial Transmission Right Options shall be awarded based only on the residual system capability that remains after the allocation of Financial Transmission Rights pursuant to Section 5.2.2(e) and the award of Financial Transmission Rights pursuant to Section 7.1.1(b) of this Schedule. Market Participants may bid for and acquire any number of Financial Transmission Rights, provided that all Financial Transmission Rights awarded are simultaneously feasible with each other and with all Financial Transmission Rights outstanding at the time of the auction and not sold into the auction. An ARR holder may self-schedule an FTR on the same path in the Annual FTR auction according to the rules described in the PJM Manuals.

(b) An Auction Revenue Rights holder may convert Auction Revenue Rights to Financial Transmission Rights, and such conversion shall not be considered a purchase or sale of Financial Transmission Rights in the auction. Such Financial Transmission Rights must (i) have the same source and sink points as the Auction Revenue Rights; (ii) be a 24-hour product; and (iii) be Financial Transmission Right Obligations. The Auction Revenue Rights holder must inform the Office of the Interconnection in accordance with the procedures established by the Office of the Interconnection that it intends to exercise the conversion option prior to close of round one of the annual Financial Transmission Rights auction. Once the conversion option is exercised, it will remain in effect for the entire Financial Transmission Rights auction. The Office of the Interconnection will designate twenty-five percent of the megawatt amount of the Auction Revenue Rights to be converted as price-taker bids in each of the four rounds of the Financial Transmission Rights auction. An Auction Revenue Rights holder that converts its Auction Revenue Rights may not designate a price bid for its converted Financial Transmission Rights and will receive a price equal to the clearing price set by other bids in the annual Financial Transmission Right auction. To the extent a market participant seeks to obtain FTRs in the annual auction through such conversion, the FTRs sought will not be included in the calculation of such market participant's credit requirement for such annual FTR auction.

7.1.2 Frequency and Time of Auctions.

Subject to Section 7.1.1 of this Schedule, annual Financial Transmission Rights auctions shall offer the entire FTR capability of the PJM system in four rounds with 25 percent of the capability offered in each round. All four rounds of the annual Financial Transmission Rights auction shall occur within the two-month period (April – May) preceding the start of the PJM Planning Period. Each round shall occur over five business days and shall be conducted sequentially. Each round shall begin with the bid and offer period. The bid and offer period for annual Financial Transmission Rights auctions shall be open for three consecutive business days, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time). Monthly Financial Transmission Rights auctions shall be held each month. The bid and offer period for monthly Financial Transmission Rights auctions shall be open for three consecutive business days in the month preceding the first month for which Financial Transmission Rights are being auctioned, opening the first day at 12:00 midnight (Eastern Prevailing Time) and closing the third day at 5:00 p.m. (Eastern Prevailing Time).

7.1.3 Duration of Financial Transmission Rights.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

Each Financial Transmission Right acquired in a Financial Transmission Rights auction shall entitle the holder to credits of Transmission Congestion Charges for the period that was specified in the corresponding auction.

7.1A Long-Term Financial Transmission Rights Auctions.

7.1A.1 Auctions.

(i) Subsequent to each annual Financial Transmission Rights auction conducted pursuant to Section 7.1 of Schedule 1 of this Agreement, the Office of the Interconnection shall conduct a long-term Financial Transmission Rights auction for the three consecutive Planning Periods immediately subsequent to the Planning Period during which the long-term Financial Transmission Rights auction is conducted. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such long-term FTR auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party.

(ii) The capacity offered for sale in long-term Financial Transmission Rights auctions shall be the residual system capability after the Annual Auction Revenue Rights allocations and the annual Financial Transmission Rights auction. In determining the residual capability the Office of the Interconnection shall assume that all Auction Revenue Rights allocated in the immediately prior annual Auction Revenue Rights allocation process are self-scheduled into Financial Transmission Rights, which shall be modeled as fixed injections and withdrawals in the long-term Financial Transmission Rights auction.

7.1A.2 Frequency and Timing.

The long-term Financial Transmission Rights auction process shall consist of three rounds. The first round shall be conducted by the Office of the Interconnection approximately 11 months prior to the start of the three Planning Period term covered by the relevant long-term Financial Transmission Rights auction. The second round shall be conducted approximately 3 months after the first round, and the third round shall be conducted approximately 3 months after the second round. In each round 1/3 of total capacity available in the long-term Financial Transmission Rights auction shall be offered for sale. Eligible entities may submit bids to purchase and offers to sell Financial Transmission Rights at the start of the bidding period in each round. The bidding period shall be three business days ending at 5:00 p.m. on the last day. PJM performs the Financial Transmission Rights auction clearing analysis for each round and posts the auction results on the market user interface within five business days after the close of the bidding period for each round. If the Office of the Interconnection discovers an error in the results posted for a long-term Financial Transmission Rights auction, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day immediately following the initial publication of the results for that auction. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified auction results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of prices for that auction. Thereafter, the Office of the Interconnection must post the corrected prices by no later than 5:00 p.m. of the fourth calendar day following the initial publication of prices in the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.1A.3 Products.

(i) The periods covered by long-term Financial Transmission Rights auctions shall be: (1) any single Planning Period within the three Planning Period term covered by the relevant auction; and (2) the three Planning Period term covered by the relevant auction.

(ii) On-Peak, off-peak and 24-hour Financial Transmission Rights obligations, as defined in Section 7.3.4 of Schedule 1 of this Agreement, shall be offered in long-term Financial Transmission Rights auctions; Financial Transmission Rights options shall not be offered.

7.1A.4 Participation Eligibility.

(i) To participate in long-term Financial Transmission Rights auctions an entity shall be a PJM Member or a PJM Transmission Customer. Eligible entities may submit bids or offers in long-term Financial Transmission Rights auctions, provided they own Financial Transmission Rights offered for sale.

7.1A.5 Specified Receipt and Delivery Points.

The Office of the Interconnection will post a list of available receipt and delivery points for each long-term Financial Transmission Rights Auction. Eligible receipt and delivery points in long-term Financial Transmission Rights Auctions shall be limited to the posted available hubs, Zones, aggregates, generators, and Interface Pricing Points.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Financial Transmission Rights auctions conducted to liquidate a defaulting Members' Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in the Section 7.3.9 herein and with the standards and procedures set forth in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Section 5.2.2 (e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 On-Peak, Off-Peak and 24-Hour Periods.

On-peak, off-peak and 24-hour FTRs will be offered in the annual and monthly auction. On-Peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on Mondays through Fridays and all hours on Saturdays, Sundays, and holidays as defined in the PJM Manuals. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for an on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offer or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Section 7.2.2 and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period,

market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Section 7.5 of this Schedule and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints.

7.3.7 Announcement of Winners and Prices.

Within two (2) business days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) business days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any

offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

7.3.9 Liquidation of Financial Transmission Rights in the Event of Member Default.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the PJM Operating Agreement or PJM Tariff, the Office of the Interconnection shall, as soon as practicable after such default is declared, initiate the following procedures to close out and liquidate the Financial Transmission Rights of a Member:

a) The Office of the Interconnection shall close out the defaulting Member’s positions as of the date of its default, by unilaterally accelerating and terminating all forward Financial Transmission Rights positions.

b) The Office of the Interconnection shall post on its website all salient information relating to the closed out portfolio of Financial Transmission Rights.

c) All current planning period Financial Transmission Right positions within the defaulting Members’ Financial Transmission Right portfolio will be offered for sale in the next available monthly balance of planning period Financial Transmission Rights auction at an offer price designed to maximize the likelihood of liquidation of those positions.

d) Financial Transmission Rights positions that do not settle until the next or subsequent planning period will be offered into the next available Financial Transmission Rights auction (taking into account timing constraints and the need for an orderly liquidation) where, based on the Office of Interconnection’s commercially reasonable expectation, such positions would be expected to clear. In the event that the next scheduled Financial Transmission Rights

auction is more than two (2) months subsequent to the date that the Office of the Interconnection declares a Member in default, a specially scheduled Financial Transmission Rights auction may be conducted by the Office of the Interconnection. The entire portfolio of the defaulting Member's Financial Transmission Rights will be offered for sale at an offer price designed to maximize the likelihood of liquidation of those positions.

e) The Financial Transmission Right positions comprising the defaulting Member's portfolio that are liquidated in a Financial Transmission Rights auction should avoid setting the price in the auction at the bid prices with which they were initially submitted. In the event that any of the closed out Financial Transmission Rights would set price based on the auction's preliminary solution, then only one-half of each Financial Transmission Rights position will be offered for sale and the auction will be re-executed. In the event that any Financial Transmission Rights position that has been closed out once again sets price, then all Financial Transmission Rights scheduled to be liquidated will be removed from the affected auction and the auction will be re-executed excluding the closed out Financial Transmission Right positions. Financial Transmission Right positions that are not liquidated will then be offered in the next available auction or specially scheduled auction, as appropriate.

f) The liquidation of the defaulting Members' Financial Transmission Rights portfolio pursuant to the foregoing procedures shall result in a final liquidated settlement amount. The final liquidated settlement amount will be included in calculating a Default Allocation Assessment as described in Section 15.1.2A(I) of the PJM Operating Agreement. If the Office of the Interconnection is unable to close out and liquidate a Financial Transmission Rights position under the foregoing procedures, the close out shall be deemed void and the defaulting Member shall remain liable for the full final value of its default, such full final value being realized at the normal time for performance of the Financial Transmission Rights position.

In all other respects, Financial Transmission Rights terminated pursuant to this section shall be liquidated pursuant to the appropriate provisions and procedures set forth in the PJM Manuals.

7.4 Allocation of Auction Revenues.

7.4.1 Eligibility.

(a) Annual auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated among holders of Auction Revenue Rights in proportion to, but not more than, the Target Allocation of Auction Revenue Rights Credits for the holder.

(b) Auction Revenue Rights Credits will be calculated based upon the clearing price results of the applicable Annual Financial Transmission Rights auction.

(c) Monthly and Balance of Planning Period FTR auction revenues, net of payments to entities selling Financial Transmission Rights into the auction, shall be allocated according to the following priority schedule:

> (i) To stage 1 and 2 Auction Revenue Rights holders in accordance with section 7.4.4 of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(ii) of this section;
>
> (ii) To the Residual Auction Revenue Rights holders in proportion to, but not more than their Target Allocation as determined pursuant to section 7.4.3(b) of Schedule 1 of this Agreement. If there are excess revenues remaining after a distribution made pursuant to this subsection, such revenues shall be distributed in accordance with subsection (c)(iii) of this section;
>
> (iii) To FTR Holders in accordance with section 5.2.6 of Schedule 1 of this Agreement.

(d) Long-term FTR auction revenues associated with FTRs that cover individual Planning Periods shall be distributed in the Planning Period for which the FTR is effective. Long-term FTR auction revenues associated with FTRs that cover multiple Planning Years shall be distributed equally across each Planning Period in the effective term of the FTR. Long-term FTR auction revenue distributions within a Planning Period shall be in accordance with the following provisions:

> (i) Long-term FTR Auction revenues shall be distributed to Auction Revenue Rights holders in the effective Planning Period for the FTR. The distribution shall be in proportion to the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately. The distribution shall not exceed, when added to the distribution of revenues from the prompt-year annual FTR auction itself, the economic value of the ARRs when compared to the annual FTR auction clearing prices from each round proportionately.

(ii) Long-term FTR auction revenues remaining after distributions made pursuant to Section 7.4.1(d)(ii) of Schedule 1 of this Agreement shall be distributed pursuant to Section 5.2.6 of Schedule 1 of this Agreement.

7.4.2 Auction Revenue Rights.

(a) Prior to the end of each PJM Planning Period an annual allocation of Auction Revenue Rights for the next PJM Planning Period shall be performed using a two stage allocation process. Stage 1 shall consist of stages 1A and 1B, which shall allocate ten year and annual Auction Revenue Rights, respectively, and stage 2 shall allocate annual Auction Revenue Rights. The Auction Revenue Rights allocation process shall be performed in accordance with Sections 7.4 and 7.5 hereof and the PJM Manuals.

With respect to the allocation of Auction Revenue Rights, if the Office of the Interconnection discovers an error in the allocation, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the business day following the initial publication of allocation results. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified allocation results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second business day following the publication of the initial allocation. Thereafter, the Office of the Interconnection must post any corrected allocation results by no later than 5:00 p.m. of the fourth calendar day following the initial publication. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced allocation is under publicly noticed review by the FERC.

(b) In stage 1A of the allocation process, each Network Service User may request Auction Revenue Rights for a term covering ten consecutive PJM Planning Periods beginning with the immediately ensuing PJM Planning Period from a subset of the historical generation resources that were designated to be delivered to load based on the historical reference year for the Zone, and each Qualifying Transmission Customer (as defined in subsection (f) of this section) may request Auction Revenue Rights based on the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. The historical reference year for all Zones shall be 1998, except that the historical reference year shall be: 2002 for the Allegheny Power and Rockland Electric Zones; 2004 for the AEP East, The Dayton Power & Light Company and Commonwealth Edison Company Zones; 2005 for the Virginia Electric and Power Company and Duquesne Light Company Zones; and the Office of the Interconnection shall specify a historical reference year for a new PJM zone corresponding to the year that the zone is integrated into the PJM Interchange Energy Market. For stage 1, the Office of the Interconnection shall determine a set of eligible historical generation resources for each Zone based on the historical reference year and assign a pro rata amount of megawatt capability from each historical generation resource to each Network Service User in the Zone based on its proportion of peak load in the Zone. Auction Revenue Rights shall be allocated to each Network Service User in a Zone from each historical generation resource in a number of megawatts equal

to or less than the amount of the historical generation resource that has been assigned to the Network Service User. Each Auction Revenue Right allocated to a Network Service User shall be to the aggregate load buses of such Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. In stage 1A of the allocation process, the sum of each Network Service User's allocated Auction Revenue Rights for a Zone must be equal to or less than the Network Service User's pro-rata share of the Zonal Base Load for that Zone. Each Network Service User's pro-rata share of the Zonal Base Load shall be based on its proportion of peak load in the Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than fifty percent (50%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined under Section 34.1 of the Tariff. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than fifty percent (50%) of the megawatts of firm service provided between the receipt and delivery points as to which the Transmission Customer had Point-to-Point Transmission Service during the historical reference year. If stage 1A Auction Revenue Rights are adversely affected by any new or revised statute, regulation or rule issued by an entity with jurisdiction over the Office of the Interconnection, the Office of the Interconnection shall, to the greatest extent practicable, and consistent with any such statute, regulation or rule change, preserve the priority of the stage 1A Auction Revenue Rights for a minimum period covering the ten (10) consecutive PJM Planning Periods ("Stage 1A Transition Period") immediately following the implementation of any such changes, provided that the terms of all stage 1A Auction Revenue Rights in effect at the time the Office of the Interconnection implements the Stage 1A Transition Period shall be reduced by one PJM Planning Period during each annual stage 1A Auction Revenue Rights allocation performed during the Stage 1A Transition Period so that all stage 1A Auction Revenue Rights that were effective at the start of the Stage 1A Transition Period expire at the end of that period.

(c) In stage 1B of the allocation process each Network Service User may request Auction Revenue Rights from the subset of the historical generation resources determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process, and each Qualifying Transmission Customer may request Auction Revenue Rights based on the megawatts of firm service determined pursuant to Section 7.4.2(b) that were not allocated in stage 1A of the allocation process. In stage 1B of the allocation process, the sum of each Network Service User's allocation Auction Revenue Rights request for a Zone must be equal to or less than the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 34.1 of the Tariff and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Network Service User's Auction Revenue Rights for Non-Zone Network Load must be equal to or less than the difference between one hundred percent (100%) of the Network Service User's transmission responsibility for Non-Zone Network Load as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone. The sum of each Qualifying Transmission Customer's Auction Revenue Rights must be equal to or less than the difference between one hundred percent (100%) of the megawatts of firm service as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Rights Allocation from stage 1A of the allocation process for that Zone.

(d) In stage 2 of the allocation process, the Office of the Interconnection shall conduct an iterative allocation process that consists of three rounds with up to one third of the remaining system Auction Revenue Rights capability allocated in each round. Each round of this allocation process will be conducted sequentially with Network Service Users and Transmission Customers being given the opportunity to view results of each allocation round prior to submission of Auction Revenue Right requests into the subsequent round. In each round, each Network Service User shall designate a subset of buses from which Auction Revenue Rights will be sourced. Valid Auction Revenue Rights source buses include only Zones, generators, hubs and external Interface Pricing Points. The Network Service User shall specify the amount of Auction Revenue Rights requested from each source bus. Each Auction Revenue Right shall be sinked to the aggregate load buses of the Network Service User in a Zone or, with respect to Non-Zone Network Load, to the border of the PJM Region. The sum of each Network Service User's Auction Revenue Rights requests in each stage 2 allocation round for each Zone must be equal to or less than one third of the difference between the Network Service User's peak load for that Zone as determined pursuant to Section 7.4.2(b) and the sum of its Auction Revenue Right Allocation from stages 1A and 1B of the allocation process for that Zone. The stage 2 allocation to Transmission Customers shall be as set forth in subsection (f).

(e) On a daily basis within the annual Financial Transmission Rights auction period, a proportionate share of Network Service User's Auction Revenue Rights for each Zone are reallocated as Network Load changes from one Network Service User to another within that Zone.

(f) A Qualifying Transmission Customer shall be any customer with an agreement for Long-Term Point-to-Point Transmission Service, as defined in the PJM Tariff, used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the Zone in which the resource is located. Such an agreement shall allow the Qualifying Transmission Customer to participate in the first stage of the allocation, but only if such agreement has remained in effect continuously following the historical reference year and is to continue in effect for the period addressed by the allocation, either by its term or by renewal or rollover. The megawatts of Auction Revenue Rights the Qualifying Transmission Customer may request in the first stage of the allocation may not exceed the lesser of: (i) the megawatts of firm service between the designated Network Resource and the load delivery point (or applicable point at the border of the PJM Region for load located outside such region) under contract during the historical reference year; and (ii) the megawatts of firm service presently under contract between such historical reference year receipt and delivery points. A Qualifying Transmission Customer may request Auction Revenue Rights in either or both of stage 1 or 2 of the allocation without regard to whether such customer is subject to a charge for Firm Point-to-Point Transmission Service under Section 1 of Schedule 7 of the PJM Tariff ("Base Transmission Charge"). A Transmission Customer that is not a Qualifying Transmission Customer may request Auction Revenue Rights in stage 2 of the allocation process, but only if it is subject to a Base Transmission Charge. The Auction Revenue Rights that such a Transmission Customer may request in each round of stage 2 of the allocation process must be equal to or less than one third of the number of megawatts equal to the megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has

Firm Point-to-Point Transmission Service. The source point of the Auction Revenue Rights must be the designated source point that is specified in the Transmission Service request and the sink point of the Auction Revenue Rights must be the designated sink point that is specified in the Transmission Service request. A Qualifying Transmission Customer may request Auction Revenue Rights in each round of stage 2 of the allocation process in a number of megawatts equal to or less than one third of the difference between the number of megawatts of firm service being provided between the receipt and delivery points as to which the Transmission Customer currently has Firm Point-to-Point Transmission Service and its Auction Revenue Right Allocation from stage 1 of the allocation process.

(g) PJM Transmission Customers that serve load in the Midwest ISO may participate in stage 1 of the allocation to the extent permitted by, and in accordance with, this Section 7.4.2 and other applicable provisions of this Schedule 1. For service from non-historic sources, these customers may participate in stage 2, but in no event can they receive an allocation of ARRs/FTRs from PJM greater than their firm service to loads in MISO.

(h) Subject to subsection (i) of this section, all Auction Revenue Rights must be simultaneously feasible. If all Auction Revenue Right requests made during the annual allocation process are not feasible then Auction Revenue Rights are prorated and allocated in proportion to the megawatt level requested and in inverse proportion to the effect on the binding constraints.

(i) If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

(j) Long-Term Firm Point-to-Point Transmission Service customers that are not Qualifying Transmission Customers and Network Service Users serving Non-Zone Network Load may participate in stage 1 of the annual allocation of Auction Revenue Rights pursuant to Section 7.4.2(a)-(c) of Schedule 1 of this Agreement, subject to the following conditions:

i. The relevant Transmission Service shall be used to deliver energy from a designated Network Resource located either outside or within the PJM Region to load located outside the PJM Region.

ii. To be eligible to participate in stage 1A of the annual Auction Revenue Rights allocation: 1) the relevant Transmission Service shall remain in effect for the stage 1A period addressed by the allocation; and 2) the control area in which the external load is located has similar rules for load external to the relevant control area.

iii. Source points for stage 1 requests authorized pursuant to this subsection 7.4.2(j) shall be limited to: 1) generation resources owned by the LSE serving the load located outside the PJM Region; or 2) generation resources subject to a bona fide firm energy and capacity supply contract executed by the LSE to meet its load obligations, provided that such contract remains in force and effect for a minimum term of ten (10) years from the first effective Planning Period that follows the initial stage 1 request.

iv. For Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) , the generation resource(s) designated as source points may include any portion of the generating capacity of such resource(s) that is not, at the time of the request, already identified as a Capacity Resource.

v. For Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j), at the time of the request, the generation resource(s) designated as source points must either be committed into PJM's RPM market or be designated as part of the entity's FRR Capacity Plan for the purpose of serving the capacity requirement of the external load.

vi. All stage 1 source point requests made pursuant to this subsection 7.4.2(j) shall not increase the megawatt flow on facilities binding in the relevant annual Auction Revenue Rights allocation or in future stage 1A allocations and shall not cause megawatt flow to exceed applicable ratings on any other facilities in either set of conditions in the simultaneous feasibility test prescribed in subsection (vii) of this subsection 7.4.2(j).

vii. To ensure the conditions of subsection (vi) of this subsection 7.4.2(j) are met, a simultaneous feasibility test shall be conducted: 1) based on next allocation year with all existing stage 1 and stage 2 Auction Revenue Rights modeled as fixed injection-withdrawal pairs; and 2) based on 10 year allocation model with all eligible stage 1A Auction Revenue Rights for each year including base load growth for each year.

viii. Requests for stage 1 Auction Revenue Rights made pursuant to this subsection 7.4.2(j) that are received by PJM by November 1st of a Planning Period shall be processed for the next annual Auction Revenue

Rights allocation. Requests received after November 1st shall not be considered for the upcoming annual Auction Revenue Rights allocation. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

ix. Requests for new or alternate stage 1 resources made by Network Service Users and external LSEs that are received by November 1st shall be evaluated at the same time. If all requests are not simultaneously feasible then requests will be awarded on a pro-rata basis.

x. Stage 1 Auction Revenue Rights source points that qualify pursuant to this subsection 7.4.2(j) shall be eligible as stage 1 Auction Revenue Rights source points in subsequent annual Auction Revenue Rights allocations.

xi. Long-Term Firm Point-to-Point Transmission Customers requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's Long-Term Firm Point-to-Point Transmission service contract megawatt amount; or 2) the customer's Firm Transmission Withdrawal Rights.

xii. Network Service Users requesting stage 1 Auction Revenue Rights pursuant to this subsection 7.4.2(j) may request Auction Revenue Rights megawatts up to the lesser of: 1) the customer's network service peak load; or 2) the customer's Firm Transmission Withdrawal Rights.

xiii. Stage 1A Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed 50% of the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j).

xiv. Stage 1B Auction Revenue Rights requests made pursuant to this subsection 7.4.2(j) shall not exceed the difference between the maximum allowed megawatts authorized by subsections (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatts granted in stage 1A.

xv. In each round of Stage 2 of an annual allocation of Auction Revenue Rights, megawatt requests made pursuant to this subsection 7.4.2(j) shall be equal to or less than one third of the difference between the maximum allowed megawatts authorized by paragraphs (xi) and (xii) of this subsection 7.4.2(j) and the Auction Revenue Rights megawatt amount allocated in stage 1.

xvi. Stage 1 Auction Revenue Rights sources established pursuant to this subsection 7.4.2(j) and the associated Auction Revenue Rights megawatt amount may be replaced with an alternate resource pursuant to the process established in Section 7.7 of Schedule 1 of this Agreement.

7.4.2a Bilateral Transfers of Auction Revenue Rights

(a) Market Participants may enter into bilateral agreements to transfer Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights to a third party. Such bilateral transfers shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(b) For purposes of clarity, with respect to all bilateral transfers of Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights, the rights and obligations to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights that are the subject of such a bilateral transfer shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. In no event, shall the purchase and sale of an Auction Revenue Right or the right to receive an allocation of Auction Revenue Rights pursuant to a bilateral transfer constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(c) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall not transfer to the third party and the holder of the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights shall continue to receive all rights attributable to the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights and remain subject to all credit requirements and obligations associated with the Auction Revenue Rights or the right to receive an allocation of Auction Revenue Rights.

(d) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the Auction Revenue Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transfer.

(e) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(f) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

7.4.3 Target Allocation of Auction Revenue Right Credits.

(a) A Target Allocation of Auction Revenue Right Credits for each entity holding an Auction Revenue Right shall be determined for each Auction Revenue Right. After each round of the annual Financial Transmission Right auction, each Auction Revenue Right shall be divided by four and multiplied by the price differences for the receipt and delivery points associated with the Auction Revenue Right, calculated as the Locational Marginal Price at the delivery points(s) minus the Locational Marginal Price at the receipt point(s), where the price for the receipt and delivery point is determined by the clearing prices of each round of the annual Financial Transmission Right auction. The daily total Target Allocation for an entity holding the Auction Revenue Rights shall be the sum of the daily Target Allocations associated with all of the entity's Auction Revenue Rights.

(b) A Target Allocation of residual Auction Revenue Rights Credits for each entity allocated Residual Auction Revenue Rights pursuant to section 7.9 of Schedule 1 of this Agreement shall be determined on a monthly basis for each month in a Planning Period beginning with the month the Residual Auction Revenue Right(s) becomes effective through the end of the relevant Planning Period. The Target Allocation for Residual Auction Revenue Rights Credits shall be equal to megawatt amount of the Residual Auction Revenue Rights multiplied by the LMP differential between the source and sink nodes of the corresponding FTR obligation in each prompt-month FTR auction that occurs from the effective date of the Residual Auction Revenue Rights through the end of the relevant Planning Period.

7.4.4 Calculation of Auction Revenue Right Credits.

(a) Each day, the total of all the daily Target Allocations determined as specified above in Section 7.4.3 plus any additional Auction Revenue Rights Target Allocations applicable for that day shall be compared to the total revenues of all applicable monthly Financial Transmission Rights auction(s) (divided by the number of days in the month) plus the total revenues of the annual Financial Transmission Rights auction (divided by the number of days in the Planning Period). If the total of the Target Allocations is less than the total auction revenues, the Auction Revenue Right Credit for each entity holding an Auction Revenue Right shall be equal to its Target Allocation. All remaining funds shall be distributed as Excess Congestion Charges pursuant to Section 5.2.5.

(b) If the total of the Target Allocations is greater than the total auction revenues, each holder of Auction Revenue Rights shall be assigned a share of the total auction revenues in proportion to its Auction Revenue Rights Target Allocations for Auction Revenue Rights which have a positive Target Allocation value. Auction Revenue Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Auction Revenue Right Credit.

(c) At the end of a Planning Period, if all Auction Revenue Right holders did not receive Auction Revenue Right Credits equal to their Target Allocations, PJMSettlement shall assess a charge equal to the difference between the Auction Revenue Right Credit Target Allocations for all revenue deficient Auction Revenue Rights and the actual Auction Revenue Right Credits allocated to those Auction Revenue Right holders. The aggregate charge for a Planning Period assessed pursuant to this section, if any, shall be added to the aggregate charge for a Planning Period assessed pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and collected pursuant to section 5.2.5(c) of Schedule 1 of this Agreement and distributed to the Auction Revenue Right holders that did not receive Auction Revenue Right Credits equal to their Target Allocation.

7.10 Financial Settlement

Financial credits and charges for Auction Revenue Rights and Financial Transmission Rights, including associated auction charges, shall be calculated and accrued on a daily basis, and included in PJMSettlement's regular invoice to each participant for the relevant period of such invoice.

7.11 PJMSettlement as Counterparty

(a) Auction Revenue Rights and Financial Transmission Rights provide certain contractual rights and obligations for the holders of such rights set forth in this Schedule 1, the Agreement, and the PJM Tariff. PJMSettlement shall be the Counterparty with respect to the contractual rights and obligations of the holders of Auction Revenue Rights, and Financial Transmission Rights.

(b) As specified in sections 5.2.2(d) and 7 of this Schedule 1, Market Participants may trade Financial Transmission Rights and Auction Revenue Rights and under certain circumstances they may convert Auction Revenue Rights to Financial Transmission Rights. PJMSettlement shall not be the counterparty with respect to bilateral transfers of Financial Transmission Rights or Auction Revenue Rights between Market Participants or the conversion of Auction Revenue Rights to Financial Transmission Rights.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com) for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than eleven business days prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, given that the electric distribution company and load serving entity must comply with a ten business day review period. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection with ten or fewer business days remaining prior to the applicable Load Management registration deadline as established by the Office of the Interconnection, then the registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration prior to the registration deadline. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection. The following general steps will be followed:

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

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An 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) an end-use customer's participation in PJM's Emergency Load Response program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting and conditioning the end-use customer participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after June 1 of the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

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

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

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the 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 Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration deadline established before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer's participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements, the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration before June 1 of the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection before June 1 of the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the 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 all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency 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.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program or notifies the requesting participant and appropriate Load Serving Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option Participants shall be the amount PJM dispatches up the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP otherwise in use for settlement of the given load or $500/MWh. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

1.1A Counterparty.

PJMSettlement is the Counterparty to obligations and all payments and distributions associated with underfrequency relay obligations and charges pursuant to this Schedule 7.