PJM Interconnection, L.L.C.
Rate Schedule FERC No. 44

RELIABILITY ASSURANCE AGREEMENT

Among

LOAD SERVING ENTITIES

in the

PJM REGION

PJM RELIABILITY ASSURANCE AGREEMENT

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RELIABILITY ASSURANCE AGREEMENT

RELIABILITY ASSURANCE AGREEMENT, dated as of this 1st day of June, 2007 by and among the entities set forth in Schedule 17 hereto, hereinafter referred to collectively as the "Parties" and individually as a "Party."

WITNESSETH:

WHEREAS, each Party to this Agreement is a Load Serving Entity within the PJM Region;

WHEREAS, each Party is committing to share its Capacity Resources with the other Parties to reduce the overall reserve requirements for the Parties while maintaining reliable service; and

WHEREAS, each Party is committing to provide mutual assistance to the other Parties during Emergencies;

WHEREAS, each Party is committing to coordinate its planning of Capacity Resources to satisfy the Reliability Principles and Standards; and

NOW THEREFORE, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

"Accredited UCAP Factor" shall mean, through the 2024/2025 Delivery Year, one minus EFORd, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

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

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

"Capacity Resources" shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6; or (iv) generation and load reduction capability provided by a DER Capacity Aggregation Resource, pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.2 and the PJM Manuals.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

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

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

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 generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

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

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

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

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 the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

DER Aggregator Officer Certification Form:

“DER Aggregator Officer Certification Form” shall mean a DER Aggregator’s certification as to an intended DER Capacity Aggregation Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

DER Capacity Aggregation Resource Sell Offer Plan:

“DER Capacity Aggregation Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of a DER Capacity Aggregation Resource in an RPM Auction, or an intended inclusion of a DER Capacity Aggregation Resource in an FRR Capacity Plan.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

"Effective UCAP" shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

"ELCC Class" shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

"ELCC Class Rating" shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

"ELCC Class UCAP" shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

"ELCC Portfolio UCAP" shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

"ELCC Resource" shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

"ELCC Resource Performance Adjustment" shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

"Electric Cooperative" shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

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

Emergency:

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

End-Use Customer:

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

Energy Efficiency Resource:

"Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency

Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

"Exigent Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

"Existing Demand Resource" shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing DER Capacity Aggregation Resource:

"Existing DER Capacity Aggregation Resource" shall mean a DER Capacity Aggregation Resource for which the DER Aggregator has identified existing Component DER that are registered in a DER Capacity Aggregation Resource for the current Delivery Year with PJM (even if not registered by such DER Aggregator) and that the DER Aggregator reasonably expects to have under a contract to generate or reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such DER Capacity Aggregation Resource is offered.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

"Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

"Facilities Study Agreement" shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

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

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall have the meaning specified in the Tariff.

Firm Service Level:

"Firm Service Level" or "FSL" of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. "Firm Service Level" or "FSL" of Demand Resource shall mean the pre-determined level for which an end-use customer's load shall be reduced, upon notification from the Curtailment Service Provider's market operations center or its agent.

Firm Transmission Service:

"Firm Transmission Service" shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

"Fixed Resource Requirement Alternative" or "FRR Alternative" shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

"Fixed-Tilt Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

"Forecast Pool Requirement" or "FPR" shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

"FRR Capacity Plan" or "FRR Plan" shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

"FRR Entity" shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

"FRR Service Area" shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

"Full Program Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

"Full Requirements Service" shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

"Gas Combined Cycle Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

"Gas Combined Cycle Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

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

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

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

Good Utility Practice:

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

Hybrid Resource Class:

“Hybrid Resource Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, the individual components would be in a Capacity Storage Resource Class, a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

“Hydropower With Non-Pumped Storage” shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

“Hydropower With Non-Pumped Storage Class” shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

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, Accredited UCAP Factor decrease, 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.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load Adjustment:

"Large Load Adjustment" shall mean any MW quantity of adjustments to summer peak load at the "zone/area" level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a "zone/area" is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

Limited Demand Resource:

"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

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

Locational Reliability Charge:

"Locational Reliability Charge" shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

"Markets and Reliability Committee" shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

"Maximum Emergency Service Level" or "MESL" of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

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

Members Committee:

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

NERC:

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

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

"Network Resources" shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

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

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

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

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

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

Offshore Wind Class:

"Offshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

"Onshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

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

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

Operating Day:

"Operating Day" shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

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

Ordinary Water Storage:

"Ordinary Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

"Other Limited Duration Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

"Other Limited Duration Combination Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

"Other Unlimited Resource Class" shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

"Other Variable Resource Class" shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

"Partial Requirements Service" shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

"Party" shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

"Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

"Performance Assessment Interval" shall have the meaning specified in Tariff, Attachment DD.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

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

PJM 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.

PJM Region:

"PJM Region" shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

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

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

Planned Demand Resource:

"Planned Demand Resource" shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned DER Capacity Aggregation Resource:

A "Planned DER Capacity Aggregation Resource" shall mean any DER Capacity Aggregation Resource that does not currently have the capability to provide generation or reduction in demand, but that is scheduled to be capable of providing such generation or reduction in demand on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6.2. As set forth in Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1, a DER Aggregator submitting a DER Capacity Aggregation Resource Sell Offer Plan shall identify in such plan all DER Capacity Aggregation Resources in excess of those that qualify as Existing DER Capacity Aggregation Resources. A Planned DER Capacity Aggregation Resource must comply with all provisions of the DER Aggregator Participation Model described in Tariff, Attachment K-Appendix, section 1.4B and Operating Agreement, Schedule 1, section 1.4B, prior to the applicable Delivery Year.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

"Planning Period" shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

"Portfolio Expected Unserved Energy" shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

"PRD Curve" shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

"PRD Provider" shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider's Zonal Expected Peak Load Value of PRD:

"PRD Provider's Zonal Expected Peak Load Value of PRD" shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

"PRD Reservation Price" shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

"PRD Substation" shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads**.**

Price Responsive Demand:

"Price Responsive Demand" or "PRD" shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

"Price Responsive Demand Credit" shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

"Price Responsive Demand Plan" or "PRD Plan" shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider's Nominal PRD Value.

Public Power Entity:

"Public Power Entity" shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

"Qualifying Transmission Upgrades" shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" or "RERRA" shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

"Reliability Principles and Standards" shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

"Required Approvals" shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

"Self-Supply" shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

"Small Commercial Customer" shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

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

State Regulatory Structural Change:

"State Regulatory Structural Change" shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

“Supervisory Control” shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

“Tracking Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

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

Transmission Owner:

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

Unforced Capacity:

"Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

"Unlimited Resource" shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

"Variable Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

"Winter Peak Load" or "WPL" shall mean the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

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.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

ARTICLE 2 -- PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, and Energy Efficiency Resources will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in RAA, Article 3, section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

ARTICLE 3 -- TERM AND TERMINATION OF THE AGREEMENT

3.1 Term.

This Agreement shall become effective as of June 1, 2007 and shall govern Unforced Capacity Obligations for the Planning Period beginning as of that date ("Initial Delivery Year"), and for each Planning Period thereafter, unless and until terminated in accordance with the terms hereof.

3.2 [Reserved for Future Use]

3.3 Termination.

3.3.1 Rights to Terminate.

This Agreement may be terminated by a vote in the Members Committee to terminate the Agreement by an affirmative Sector Vote as specified in the Operating Agreement and upon the receipt of all Required Approvals related to the termination of this Agreement. Any such termination must be approved by the PJM Board and filed with the FERC and shall become effective only upon the FERC's approval.

3.3.2 Obligations upon Termination.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (a) final settlement of the obligations of each Party under RAA, Article 8 and RAA, Article 12, including the accounting for the period ending with the last day of the month for which the Agreement is effective, (b) the provisions of this Agreement necessary to conduct final billings, collections and accounting with respect to all matters arising hereunder and (c) the indemnification provisions as applicable to periods prior to such termination.

ARTICLE 4 -- ADDITION OF NEW PARTIES

Each Party agrees that any entity that (i) is or will become a Load Serving Entity, (ii) complies with the process and data requirements set forth in RAA, Schedule 1, and (iii) meets the standards for interconnection set forth in RAA, Schedule 2 shall become a Party to this Agreement and shall be listed on RAA, Schedule 17 upon becoming a party to the Operating Agreement, and execution of a counterpart of this Agreement.

ARTICLE 5 -- WITHDRAWAL OR REMOVAL OF A PARTY

5.1 Withdrawal of a Party.

5.1.1 Notice.

Upon written notice to the Office of the Interconnection, any Party may withdraw from this Agreement, effective upon the completion of its obligations hereunder and the documentation by such Party, to the satisfaction of the Office of the Interconnection, that such Party is no longer a Load Serving Entity.

5.1.2 Determination of Obligations.

A Party's obligations hereunder shall be completed as of the end of the last month for which such Party’s obligations have been set at the time said notice is received, except as provided in RAA, Article 13, or unless the Members Committee determines that the remaining Parties will be able to adjust their obligations and commitments related to the performance of this Agreement consistent with such earlier withdrawal date as may be requested by the withdrawing Party, without undue hardship or cost, while maintaining the reliability of the PJM Region.

5.1.3 Survival of Obligations upon Withdrawal.

(a) The obligations of a Party upon its withdrawal from this Agreement and any obligations of that Party under this Agreement at the time of its withdrawal shall survive the withdrawal of the Party from this Agreement. Upon the withdrawal of a Party from this Agreement, final settlement of the obligations of such Party under RAA, Article 7 and RAA, Article 11 shall include the accounting through the date established pursuant to RAA, Article 5, section 5.1.1 and RAA, Article 5, section 5.1.2.

(b) Any Party that withdraws from this Agreement shall pay all costs and expenses associated with additions, deletions and modifications to communication, computer, and other affected facilities and procedures, including any filing fees, to effect the withdrawal of the Party from the Agreement.

(c) Prior to withdrawal, a withdrawing Party desiring to remain interconnected with the PJM Region shall enter into a control area to control area interconnection agreement with the Office of the Interconnection and the transmission owner or Electric Distributor within the PJM Region with which its facilities are interconnected.

5.1.4 Regulatory Review.

Any withdrawal from this Agreement shall be filed with FERC and shall become effective only upon FERC's approval.

5.2 Breach by a Party.

The provisions of Operating Agreement, section 15.1 shall apply to a Party's (a) failure to pay any amount due under this Agreement when due or (b) breach of any material obligation under this Agreement. In addition to the remedies available to the Office of the Interconnection set forth in Operating Agreement, section 15.1, if the Party fails to cure such non-payment or breach, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (a) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (b) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).

ARTICLE 6 -- MANAGEMENT ADMINISTRATION

Except as otherwise provided herein, this Agreement shall be managed and administered by the Parties, Members, and State Consumer Advocates through the Members Committee and the Markets and Reliability Committee as a Standing Committee thereof, except as delegated to the Office of the Interconnection and except that only the PJM Board shall have the authority to approve and authorize the filing of amendments to this Agreement with the FERC.

ARTICLE 7 -- RESERVE REQUIREMENTS AND OBLIGATIONS

7.1 Forecast Pool Requirement and Unforced Capacity Obligations.

(a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. RAA, Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

7.2 Responsibility to Pay Locational Reliability Charge.

Except to the extent its capacity obligations are satisfied through the FRR Alternative, each Party shall pay, as to the loads it serves in each Zone during a Delivery Year, a Locational Reliability Charge for each such Zone during such Delivery Year. The Locational Reliability Charge shall equal such Party's Daily Unforced Capacity Obligation in a Zone, as determined pursuant to RAA, Schedule 8, times the Final Zonal Capacity Price for such Zone, as determined pursuant to Tariff, Attachment DD.

7.3 LSE Option to Provide Capacity Resources.

A Party obligated to pay a Locational Reliability Charge for a Delivery Year may partially or wholly offset amounts it must pay for such charge by offering Capacity Resources for sale in the Base Residual Auction or an Incremental Auction applicable to such Delivery Year; provided such resources clear such auctions. Resources offered for sale in any such auction must satisfy the requirements specified in this Agreement and the PJM Manuals. Such a Party may choose to nominate a resource in the Base Residual Auction as Self-Supply, may choose to designate a price offer for such resource into any such auction, or may indicate in its offer that it wishes to commit such resource regardless of the clearing price, in which case the Party shall receive the marginal value of system capacity and the price adders for any applicable binding locational constraint in accordance with Attachment DD of the PJM Tariff. Each such Party acknowledges that the clearing price it receives for a resource offered for sale and cleared, or Self-Supplied, in an auction may differ from the Final Zonal Capacity Price determined for the applicable Zone for the applicable Delivery Year, and that the Party shall remain responsible for the Locational Reliability Charge notwithstanding any such difference between the Capacity Resource Clearing Price and the Final Zonal Capacity Price. In addition, such Parties recognize that they may receive an allocation of Capacity Transfer Rights which may offset a portion of the Locational Reliability Charge, and that they may offset a portion of the Locational Reliability Charge by offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

7.4 Fixed Resource Requirement Alternative.

A Party that is eligible for the Fixed Resource Requirement Alternative may satisfy its obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan and meeting all other terms and conditions of such alternative, as set forth in this Agreement.

7.5 Capacity Plans and Deliverability.

Each Party electing to provide Capacity Resources to meet its obligations hereunder shall submit to the Office of the Interconnection its plans (or revisions to previously submitted plans), as prescribed by RAA, Schedule 7, or, in the case of a Party electing the FRR Alternative, as prescribed by RAA, Schedule 8.1, to install or contract for Capacity Resources. As set forth in RAA, Schedule 10, each Party must designate its Capacity Resources as Network Resources or Points of Receipt under the PJM Tariff to allow firm delivery of the output of its Capacity Resources to the Party's load within the PJM Region and each Party must obtain any necessary Firm Transmission Service in an amount sufficient to deliver Capacity Resources from outside the PJM Region to the border of the PJM Region to reliably serve the Party's load within the PJM Region.

7.6 Nature of Resources.

Each Party electing to Self-Supply resources, or electing the FRR Alternative, shall provide or arrange for specific, firm Capacity Resources that are capable of supplying the energy requirements of its own load on a firm basis without interruption for economic conditions and with such other characteristics that are necessary to support the reliable operation of the PJM Region, as set forth in more detail in RAA, Schedule 6, RAA, Schedule 9 and RAA, Schedule 10.

7.7 Compliance Audit of Parties.

(a) For the 36 months following the end of each Planning Period, each Party shall make available the records and supporting information related to the performance of this Agreement from such Planning Period for audit.

(b) The Office of the Interconnection shall evaluate and determine the need for an audit of a Party and shall, upon a decision of the Members Committee to require such an audit, provide the Party or Parties to be audited with notice at least 90 days in advance of the audit.

(c) Any audit of a Party conducted pursuant to this Agreement shall be performed by an independent consultant to be selected by the Office of the Interconnection. Such audit shall include a review of the Party's compliance with the procedures and standards adopted pursuant to this Agreement.

(d) Prior to the completion of its audit, the independent consultant shall review its preliminary findings with the Party being audited and, upon the completion of its audit, the independent consultant shall issue a final audit report detailing the results of the audit, which final report shall be issued to the Party being audited, the Office of the Interconnection and the Markets and Reliability Committee; provided, however, no confidential data of any Party shall be disclosed through such audit reports.

(e) If, based on a final audit report, an adjustment is required to any amounts due to or from the Parties pursuant to Schedules 8, 12, or 13, such adjustment shall be accounted for in determining the amounts due to or from the Parties pursuant to Schedules 8, 12, or 13 for the month in which the adjustment is identified.

ARTICLE 8 -- DEFICIENCY, DATA SUBMISSION, AND EMERGENCY CHARGES

8.1 Nature of Charges.

Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement.

8.2 Determination of Charge Amounts.

No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period , which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.

8.3 Distribution of Charge Receipts.

All of the monies received as a result of any charges imposed pursuant to this Agreement shall be disbursed as provided in this Agreement.

ARTICLE 9 -- COORDINATED PLANNING AND OPERATION

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a) cooperate with the members and associate members of such Party's Applicable Regional Entity to ensure the reliability of the region;

(b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.2 Generator Planned Outage Scheduling.

Each Party shall develop, or cause to be developed, its schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, in RAA, Schedule 11.

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Tariff, Attachment DD, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.

(b) A data submission charge, as set forth in RAA, Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in RAA, Schedule 11.

9.5 Metering.

Each Party shall comply with the metering standards for the PJM Region, as set forth in the PJM Manuals, as well as any further metering requirements applicable to Price Responsive Demand, where such is relied upon for an adjustment to peak load pursuant to RAA, Schedule 6.1.

ARTICLE 10 -- SHARED COSTS

10.1 Recording and Audit of Costs.

(a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

10.2 Cost Responsibility.

The costs determined under RAA, Article 10, section 10.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Tariff, Schedule 9-5.

ARTICLE 11 -- BILLING AND PAYMENT

11.1 Periodic Billing.

Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Party's share of any costs allocated to that Party pursuant to RAA, Article 10. To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Operating Agreement or PJM Tariff.

11.2 Payment.

The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

11.3 Failure to Pay.

If any Party fails to pay its share of the costs allocated pursuant to Article 10, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Daily Unforced Capacity Obligations of each such Party for the billing month. The Office of the Interconnection shall enforce collection of a Party's share of the costs.

ARTICLE 12 -- INDEMNIFICATION AND LIMITATION OF LIABILITIES

12.1 Indemnification.

(a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (other than PJM Interconnection, L.L.C., its board or the Office of the Interconnection) for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law. Nothing herein shall limit a Party's indemnity obligations under Operating Agreement, section 16.

(b) The amount of any indemnity payment under this section 12.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

12.2 Limitations on Liability.

No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

12.3 Insurance.

Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM Region.

ARTICLE 13 -- SUCCESSORS AND ASSIGNS

13.1 Binding Rights and Obligations.

The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

13.2 Consequences of Assignment.

Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of RAA, Article 13, section 13.1, the assignor shall be deemed to have withdrawn from this Agreement.

ARTICLE 14 -- NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

ARTICLE 15 -- REPRESENTATIONS AND WARRANTIES

15.1 Initial Representations and Warranties.

Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

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

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

15.2 Continuing Representations and Warranties.

Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of RAA, Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in RAA, Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

ARTICLE 16 -- OTHER MATTERS

16.1 Relationship of the Parties.

This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

16.2 Governing Law.

This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

16.3 Severability.

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

16.4 Amendment.

This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an Applicant eligible to become a Party in accordance with the procedures set forth in RAA, Article 4 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The PJM Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

16.5 Headings.

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

16.6 Confidentiality.

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

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

16.7 Counterparts.

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

16.8 No Implied Waivers.

The failure of a Party 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 Party'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.

16.9 No Third Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

16.10 Dispute Resolution.

Except as otherwise specifically provided in the Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Operating Agreement.

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

[Signatures]

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM Region and thus a Party to the Reliability Assurance Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date the Reliability Assurance Agreement is to become effective as to that entity) satisfy the requirements to become a Party, (ii) all data required to coordinate planning and operations within the PJM Region as applicable, in a format defined in the PJM Manuals, and (iii) a deposit in an amount to be specified that will be applied toward the costs of the required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

- If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for transmission service under the PJM Tariff.

- If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM Region or (ii) in which any agency relationship through which the entity's obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Tariff associated with providing service to those loads.

B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM Region.

C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entity's share of any costs pursuant to RAA, Article 10, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Markets and Reliability Committee and execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Region's interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Region's standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

- Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 9.1(d); and

- The Operating Agreement.

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than 75 days in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in RAA, Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) seasonal peak diversities determined by the Office of the Interconnection.

2. Variability of loads within each week through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, hourly load shapes and variability, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

3. Generating unit capability and types for every existing and proposed unit.

4. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent and historical experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

5. Generator Maintenance Outage factors and planned outage factors as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

6. Miscellaneous adjustments to capacity due to all causes, including weather, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

7. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

D. Capacity Benefit Margin

The capacity benefit margin initially shall be 3,500 megawatts. Periodically, in consultation with the Members Committee, the Office of the Interconnection shall review and modify, if necessary, the capacity benefit margin to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the Parties, consistent with the Reliability Principles and Standards. The Office of the Interconnection will reflect such modification prospectively in its development of the Forecast Pool Requirement for future Planning Periods.

SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Through the 2024/2025 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (1\text{- Pool-wide average } EFOR_D)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. Through the 2024/2025 Delivery Year, the PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to RAA, Schedule 5.

C. Beginning with the 2025/2026 Delivery Year, the Forecast Pool Requirement shall be determined in accordance with the following:

Based on the guidelines set forth in RAA, Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM) * (\text{Pool-wide average Accredited UCAP Factor})$$

where

Pool-wide average Accredited UCAP Factor = the ratio of the total Accredited UCAP to total installed capacity of all resources, as determined pursuant to RAA, Schedule 9.2, that are included in the determination of the Forecast Pool Requirement, stated in percent

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent.

SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D\ (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For Delivery Years through the 2024/2025 Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year.

Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

For Delivery Years through the 2024/2025 Delivery Year, the forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C outages deemed to be outside plant management control in accordance with NERC guidelines shall be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand

Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter

Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter, Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources – all provisions in RAA, Schedule 6, section L and Tariff, Attachment DD-1, section L shall be effective only through the 2025/2026 Delivery Year. Thereafter, no Energy Efficiency Resources shall qualify to be offered into the RPM Auctions beginning with the 2026/2027 Delivery Year.

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or

systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the

Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver

Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

SCHEDULE 6.1

PRICE RESPONSIVE DEMAND

A. As more fully set forth in this Schedule 6.1 and the PJM Manuals, for any Delivery Year beginning on or after June 1, 2015 (subject to a transition plan, as set forth below), any PRD Provider, including any FRR Entity, may commit that certain loads identified by such PRD Provider shall not exceed a specified demand level at specified prices during Maximum Generation Emergencies for the 2020/2021 and 2021/2022 Delivery Years or at specified prices during a Performance Assessment Interval for the 2022/2023 Delivery Year and subsequent Delivery Years, as a consequence of the implementation of Price Responsive Demand. Based on information provided by the PRD Provider in a PRD Plan (and, to the extent such plan identifies a PRD Reservation Price, based on the clearing price in the Base Residual Auction or Third Incremental Auction, as applicable), the Office of the Interconnection shall determine the Nominal PRD Value for the specified loads identified by such PRD Provider by Zone (or sub-Zonal LDA, if applicable). The Office of the Interconnection shall adjust the PJM Region Reliability Requirement and LDA Reliability Requirements, as applicable, to reflect committed PRD. Actual PRD reductions in response to price shall be added back in determining peak load contributions as set forth in the PJM Manuals. Any PRD Provider that fails to fully honor its PRD commitments for a Delivery Year shall be assessed compliance charges.

B. End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response, Pre-Emergency Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider; or (iv) include Critical Natural Gas Infrastructure.

C. Any PRD Provider seeking to commit PRD hereunder for a Delivery Year must submit to the Office of the Interconnection a PRD Plan identifying and supporting the Nominal PRD Value (for the 2020/2021 and 2021/2022 Delivery Years, calculated as the difference between the PRD Provider's Zonal Expected Peak Load Value of PRD and the Maximum Emergency Service Level of Price Responsive Demand or for the 2022/2023 Delivery Year and subsequent Delivery Years, calculated as the peak load contribution minus Firm Service Level times loss factor for each Zone (or sub-Zonal LDA, if applicable) for which such PRD is committed; such information shall be provided on a PRD Substation level to the extent available at the time the PRD Plan is submitted. Such plan must be submitted no later than (a) March 17, 2019 for the Base Residual Auction for the 2022/2023 Delivery Year or (b) the January 15 that last precedes the Base Residual Auction for the 2023/2024 and subsequent Delivery Years for which such PRD is committed; any submitted plan that does not contain, by such applicable deadline, all information required hereunder shall be rejected. A PRD Provider may submit a PRD Plan, or a modified PRD Plan, by the January 15 last preceding the Third Incremental Auction for such Delivery Year requesting approval of additional Price Responsive Demand but only in the event, and to the extent, that the final peak load forecast for the relevant LDA for such Delivery Year exceeds the preliminary peak load forecast for such LDA and Delivery Year. Notwithstanding the foregoing, any PRD Plan submitted and approved for the 2022/2023 Delivery Year may be withdrawn or modified no later than 30 days prior to the commencement of the Base Residual Auction. The Office of the Interconnection shall revise such requests (as adjusted, to the extent a PRD Reservation Price is specified, for the results of the Third Incremental Auction) for additional Price Responsive Demand downward, in accordance with rules in the PJM Manuals, if the submitted requests (as adjusted) in the aggregate exceed the increase in the load forecast in the LDA modeled. The Office of the Interconnection shall advise the PRD Provider, following the Third Incremental Auction, of its acceptance of, or any downward adjustment to, the Nominal PRD Value based on its review of the PRD Plan and the results of the auction. Approval of the PRD Plan by the Office of the Interconnection shall establish a firm commitment by the PRD Provider to the specified Nominal PRD Value of Price Responsive Demand at each Zone (or sub-Zonal LDA, if applicable) during the relevant Delivery Year (subject to any PRD Reservation Price), and may not be uncommitted or replaced by any Capacity Resource. Although the PRD Plan may include reasonably supported forecasts and expectations concerning the development of Price Responsive Demand for a Delivery Year, the PRD Provider’s commitment to a Nominal PRD Value for such Delivery Year shall not depend or be conditioned upon realization of such forecasts or expectations.

D. All submitted PRD Plans must comply with the requirements and criteria in the PJM Manuals for such plans, including assumptions and standards specified in the PJM Manuals for estimates of expected load levels (prior to 2022/2023 Delivery Year) and estimates of peak load contribution (for the 2022/2023 Delivery Year and subsequent Delivery Years) as described in paragraph C. The PRD Plan shall explain and justify the methods used to determine the Nominal PRD Value. All assumptions and relevant variables affecting the Nominal PRD Value must be clearly stated. The PRD Plan must include sufficient data to allow a third party to audit the procedures and verify the Nominal PRD Value. Any non-compliance with a Nominal PRD Value for a prior Delivery Year shall be identified and taken into account. In addition, each submitted PRD Plan must include:

(i) documentation, in the form specified in the PJM Manuals, that the PRD Provider has in place contractual arrangements with the relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements, and adheres to PRD implementation standards specified in the PJM Manuals; in such cases, the PRD Provider shall provide the Office of the Interconnection copies of its applicable contracts with end-use customers (including any proposed contracts) within ten Business Days after a request for such contracts, or its PRD Plan shall be rejected;

(ii) prior to the 2022/2023 Delivery Year the expected peak load value that would apply, absent load reductions in response to price, to the end-use customer loads at a PRD Substation level, including applicable peak-load contribution data for such customers, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level. For the 2022/2023 Delivery Year and subsequent Delivery Years, estimates of Peak Load Contribution at a PRD Substation level, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iii) the Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year) or Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) of the identified load given the load's price-responsive characteristics, at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iv) Price-consumption curves ("PRD Curves") at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level that detail the base consumption level of the identified loads; and the decreasing consumption levels at increasing prices, provided that all identified load reductions must be capable of full implementation within 15 minutes of declaration of a Maximum Generation Emergency (prior to 2022/2023 Delivery Year) or Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) by the Office of the Interconnection, and provided further that the specified prices may not exceed the maximum energy offer price cap under the PJM Tariff and Operating Agreement;

(v) the estimated Nominal PRD Value of the Price Responsive Demand at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(vi) specifications of equipment used to satisfy the advanced metering and Supervisory Control criteria for eligible Price Responsive Demand, including a timeline and milestones demonstrating that such equipment shall be available and operational for the start of the relevant Delivery Year. Such equipment shall comply with applicable RERRA requirements and shall be designed to meet all PRD requirements, including, without limitation, meter reading requirements and Supervisory Control requirements, specified in the PJM Manuals. The PRD Provider shall demonstrate in the PRD Plan that the Supervisory Control equipment enables an automated load response by Price Responsive Demand to the price trigger; provided, however, that the PRD Provider may request in the PRD Plan an exception to the automation requirement for any individual registered end-use customer that is located at a single site and that has Supervisory Control over processes by which load reduction would be accomplished; and provided further that nothing herein relieves such end-use customer of the obligation to respond within 15 minutes to declaration of a Maximum Generation Emergency (prior to 2022/2023 Delivery Year) or a Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) in accordance with applicable PRD Curves. In addition to the above requirements and those in the PJM Manuals for metering equipment and associated data, metering equipment shall provide integrated hourly kWh values on an electric distribution company account basis and 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). The installed metering equipment must be that used for retail electric service; or metering equipment owned by the end-use customer or PRD Provider that is approved by PJM and either read electronically by PJM or read by the customer or PRD Provider and forwarded to PJM, in either case in accordance with requirements set forth in the PJM Manuals; and

(vii) any RPM Auction clearing price below which the PRD Provider does not choose to commit PRD ("PRD Reservation Price"), specifying the relevant auction, Zone (or sub-Zonal LDA if applicable), and, if applicable, a range of up to ten pairs of PRD commitment levels and associated minimum RPM Auction clearing prices; provided however that the Office of the

Interconnection may interpolate PRD commitment levels based on clearing prices between prices specified by the PRD Provider.

E. Each PRD Provider that commits Price Responsive Demand through an accepted PRD Plan must, no later than one day before the tenth Business Day prior to the start of the Delivery Year for which such PRD is committed, register with PJM, in the form and manner specified in the PJM Manuals, sufficient PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment. All information required in the PRD Plan to be at a PRD Substation level if available at the time of submission of the PRD Plan that was not provided at the time of submission of such plan must be provided with the registration. The PRD Provider shall also identify in the registration each individual end-use customer with a peak load contribution of 10 kW or greater included in such Price Responsive Demand, the peak load contribution, Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year), and Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such customers. PJM shall provide notification of such PRD registrations to the applicable electric distribution company(ies). The PRD Provider shall maintain, and provide to the Office of the Interconnection upon request, an identification of all individual end-use customers with a peak load contribution of less than 10kW included in such Price Responsive Demand, and the peak load contribution, Maximum Emergency Service Level (prior to the 2022/2023 Delivery Year), and Firm Service Levels (for the 2022/2023 Delivery Year and subsequent Delivery Years) of such customers. The PRD Provider must maintain its PRD Substation-level registration of PRD-eligible load at the level of its Zonal (or sub-zonal LDA, if applicable) Nominal PRD Value commitment during each day of the Delivery Year for which such commitment was made. The PRD Provider may change the end-use customer registered to meet the PRD Provider's commitment during the Delivery Year, but such PRD Provider must always in the aggregate register sufficient Price Responsive Demand to meet or exceed the Zonal (or sub-Zonal LDA, if applicable) committed Nominal PRD Value level. A PRD Provider must timely notify the Office of the Interconnection, in accordance with the PJM Manuals, of all changes in PRD registrations. Such notification must remove from the PRD Provider's registration(s) any end-use customer load that no longer meets the eligibility criteria for PRD, effective as of the first day that such end-use customer load is no longer PRD-eligible.

F. Each PRD Provider shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Real-Time Energy Market. The most recent PRD Curve submitted by the PRD Provider in its PRD Plan or PRD registration shall be used for such purpose unless and until changed by the PRD Provider in accordance with the market rules of the Office of the Interconnection, provided that any changes to PRD Curves must be consistent with the PRD Provider's commitment of Price Responsive Demand hereunder.

G. The PRD Provider shall receive a Price Responsive Demand Credit for such registrations during the Delivery Year, in such Zone for such day, determined as follows:

PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling

Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].

For the 2022/2023 Delivery Year and subsequent Delivery Years, the factor equal to FZWNSP/FZPLDY is eliminated in the calculation of the LSE PRD Credit

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration .

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year;

And where the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone. A PRD Provider will receive a PRD Credit for each approved Price Responsive Demand registration that is effective on a given day. The total daily credit to a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day.

H. A PRD Provider may transfer all or part of its PRD commitment for a Delivery Year in a Zone (or sub-Zonal LDA) to another PRD Provider for its use in the same Zone or sub-Zonal LDA, through notice of such transfer provided by both the transferor and transferee PRD Providers to the Office of the Interconnection in the form and manner specified in the PJM Manuals. From and after the effective date of such transfer, and to the extent of such transfer, the transferor PRD Provider shall be relieved of its PRD commitment and credit requirements, shall not be liable for PRD compliance charges, and shall not be entitled to a Price Responsive Demand Credit; and the transferee PRD Provider, to the extent of such transfer, shall assume such PRD commitment, credit requirements, obligation for compliance charges and shall be entitled to a Price Responsive Demand Credit.

I. Any PRD Provider that commits Price Responsive Demand and does not register and maintain registration of sufficient PRD-eligible load, (including, without limitation, failing to install or maintain the required advanced metering or Supervisory Control facilities) in a Zone (or sub-Zonal LDA, if applicable) to satisfy in full its Nominal PRD Value commitment in such Zone (or sub-Zonal LDA) on each day of the Delivery Year for which such commitment is made shall be assessed a compliance charge for each day that the registered Price Responsive Demand is less than the committed Nominal PRD Value. Such daily penalty shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Weighted Final Zonal Capacity Price) or ($20/MW-day)]

Where: MW Shortfall = Daily Nominal PRD Value committed in such PRD Provider's PRD Plan (including any permitted amendment to such plan) for the relevant Zone or sub-Zonal LDA – Daily Nominal PRD Value as a result of PRD registration for such Zone or sub-Zonal LDA; and

Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction.

The MW Shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits, provided, however, that the PRD Provider may register additional PRD-eligible end-use customer load to satisfy its PRD commitment.

J. PRD Providers shall be responsible for verifying the performance of their PRD loads during each maximum emergency event (prior to the 2022/2023 Delivery Year) and Performance Assessment Interval (for the 2022/2023 Delivery Year and subsequent Delivery Years) declared by the Office of the Interconnection. PRD Providers shall demonstrate that the identified PRD loads performed in accordance with the PRD Curves submitted at a PRD Substation level in the PRD Plan or PRD registration; provided, however, prior to the 2022/2023 Delivery Year, the previously submitted Maximum Emergency Service Level ("MESL") value shall be adjusted by a ratio equal to the amount by which the actual Zonal load during the declared event exceeded the PJM load forecast underlying the previously submitted MESL value. In accordance with procedures and deadlines specified in the PJM Manuals, the PRD Providers must submit actual customer load levels for all hours during the declared event and all other information reasonably required by the Office of the Interconnection to verify performance of the committed PRD loads.

K. Prior to the 2022/2023 Delivery Year, if the identified loads submitted for a Zone (or sub-Zonal LDA) by a PRD Provider exceed during any Emergency the aggregate MESL specified in all PRD registrations of such PRD Provider that have a PRD Curve specifying a price at or below the highest Real-time LMP recorded during such Emergency, the PRD Provider that committed such loads as Price Responsive Demand shall be assessed a compliance charge hereunder. The charge shall be based on the net performance during an Emergency of the loads that were identified as Price Responsive Demand for such Delivery Year in the PRD registrations submitted by such PRD Provider in each Zone (or sub-Zonal LDA, if applicable) and that specified a price at the MESL that is at or below the highest Real-Time LMP recorded during such Emergency. The compliance charge hereunder shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Final Zonal Capacity Price) or ($20/MW-day)] * 365 days

Where: MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA meeting the price condition specified above]

– {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone meeting the price condition specified above)]}.

For purposes of the above provision, the MW Shortfall for any portion of the Emergency event that is less than a full clock hour shall be treated as a shortfall for a full clock hour unless either: (i) the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification, regardless of the response rate submitted, or (ii) the hourly integrated value of the load was at or below the adjusted MESL. Such MW shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits; provided, however, that the performance and MW Shortfalls of all PRD-eligible load registered by the PRD Provider, including any additional or replacement load registered by such PRD Provider, provided that it meets the price condition specified above, shall be reflected in the calculation of the overall MW Shortfall. Any greater MW Shortfall during a subsequent Emergency for such Zone or sub-Zonal LDA during the same Delivery Year shall result in a further charge hereunder, limited to the additional increment of MW Shortfall. As appropriate, the MW Shortfall for non-compliance during an Emergency shall be adjusted downward to the extent such PRD Provider also was assessed a compliance penalty for failure to register sufficient PRD to satisfy its PRD commitment.

L. PRD Providers that register Price Responsive Demand shall be subject to test at least once per year to demonstrate the ability of the registered Price Responsive Demand to reduce to the specified Maximum Emergency Service Level prior to the 2022/2023 Delivery Year or the Firm Service Level for the 2022/2023 Delivery Year and subsequent Delivery Years, and such PRD Providers shall be assessed a compliance charge to the extent of failure by the registered Price Responsive Demand during such test to reduce to the relevant service level, in accordance with the following:

(i)

(a) Prior to the 2022/2023 Delivery Year, if the Office of the Interconnection does not declare during the relevant Delivery Year a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level is called during the relevant Delivery Year, then no compliance charges will be assessed hereunder.

(b) For the 2022/2023 Delivery Year, if the Office of the Interconnection does not declare an Emergency Action triggering a Performance Assessment Interval during the relevant Delivery Year or is not measured for compliance at a Performance Assessment Interval, then such registered PRD must demonstrate that it was tested for a one hour period between 10:00 AM EPT to 10:00 PM EPT during June through October or the following May of the relevant Delivery Year. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

(c) For the 2023/2024 Delivery Year and subsequent Delivery Years, if the registered PRD is not required to reduce the load for a Performance Assesment Interval during the relevant Delivery Year, then such registered PRD shall test for a two hour period between 11:00 EPT to 18:00 EPT on a weekday that is a non-NERC holiday during the relevant Delivery Year and in accordance with the following provisions. The Office of Interconnection shall schedule, on an alternating basis, one test during June through October or November through March for each Delivery Year that a test is required. The date and time of such test shall be selected by the Office of the Interconnection and notice of such test shall be provided to the PRD Provider in accordance with the procedure described in this section L.ii(b). If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

(ii)

(a) Prior to the 2023/2024 Delivery Year, all PRD registered in a Zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

(b) For the 2023/2024 Delivery Year and subsequent Delivery Years, all PRD registered in a zone will be tested simultaneously for two hours. The Office of the Interconnection may, at its discretion, cancel a test and retest to ensure system reliability.

If less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct re-tests limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

If 25 percent or more (by megawatts) of a PRD Provider's total PRD registered in a Zone fails the test the PRD Provider may request PJM to schedule a one-time retest limited to all registrations that failed the prior test, provided that all affiliated registrations must test simultaneously where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest can be conducted in May) and notice is provided consistent with the following procedure.

(c) Notification of the initial Office of the Interconnection scheduled test will be provided as follows:

On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date. The Office of the Interconnection will also notify the PRD Providers the test date. On test date, PRD Providers will receive start time through web service communications and as defined in the PJM Manuals.

Notification of any scheduled retest by the Office of the Interconnection will be provided as follows:

By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the PRD Providers the retest date. On retest date PRD Providers will receive start time through web service communications and as defined in the PJM Manuals.

(iii) A PRD Provider that registered PRD shall be assessed a PRD Test Failure Charge equal to the net PRD capability testing shortfall in a Zone during such test in the aggregate of all of such PRD Provider's registered PRD in such Zone times the PRD Test Failure Charge Rate. Prior to the 2022/2023 Delivery Year, the net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement:

MW Shortfall = [hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone]}.

The net PRD capability testing shortfall in such Zone shall be reduced by the PRD Provider's summer daily average of the MW shortfalls determined for compliance charge purposes under section I of this Schedule 6.1 in such Zone for such PRD Provider's registered PRD.

For the 2022/2023 Delivery Year and subsequent Delivery Years, the MW testing shortfall for a PRD registration is equal to the nominal load reduction value of such registration, capped at the daily Nominal PRD Value committed by such registration on the day of the test, minus the actual hourly load reduction for such registration. The test compliance results of the PRD Provider's registrations in a Zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall.

(iv) The PRD Test Failure Charge Rate shall equal such PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year, where the Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction.

M. The revenue collected from assessment of the charges assessed under subsections I, K, and L of this Schedule 6.1 shall be distributed on a pro-rata basis to all entities that committed Capacity Resources in the RPM Auctions for the Delivery Year for which the compliance charge is assessed, pro rata based on each such entity's revenues from Capacity Market Clearing Prices in such auctions, net of any compliance charges incurred by such entity.

N. For the 2022/2023 Delivery Year and subsequent Delivery Years, a PRD Provider is subject to a Non-Performance Assessment in accordance with the PJM Tariff, Attachment DD, section 10A. Compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval in same sub-Zone/Zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point at or below the Real-time LMP recorded during the Performance Assessment Interval. A PRD registration with an approved exception to the automation requirement will not have compliance measured during Performance Assessment Intervals that fall within the 15 minute response allowance. The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's peak load contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the peak load contribution. When five minute revenue meter data is not available to determine compliance of a PRD registration for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction for the hour ending that includes the Performance Assessment Interval(s) multiplied (twelve divided by the number of five minute intervals the PRD registration was to be measured for compliance). The actual load reduction for a registration for a Performance Assessment Interval is capped at the peak load contribution of the registration. If the PRD Provider fails to submit actual metered data for the registration for all hours during the day of a Performance Assessment Interval, the actual load reduction for such registration will be equal to zero MW.

SCHEDULE 6.2

DER Capacity Aggregation Resources qualifying under the criteria set forth below may be offered for sale in an RPM auction, or included in an FRR Capacity Plan, for any Delivery Year for which such resource qualifies.

DER Aggregators intending to offer for sale or designate for self-supply, a DER Capacity Aggregation Resource in any RPM Auction, or intending to include a DER Capacity Aggregation Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide generation or reduction in demand, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such DER Aggregator shall submit a DER Capacity Aggregation Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6.2, and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included.

PJM may verify the DER Aggregator's adherence to the DER Capacity Aggregation Resource Sell Offer Plan at any time. A DER Aggregator with a PJM-approved DER Capacity Aggregation Resource Sell Offer Plan will be permitted to offer up to the approved megawatt quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

A DER Capacity Aggregation Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a DER Aggregator Officer Certification Form signed by an officer of the DER Aggregator that is duly authorized to provide such a certification. The DER Capacity Aggregation Resource Sell Offer Plan must provide information that supports the DER Aggregator's intended DER Capacity Aggregation Resource Sell Offers and demonstrate that the DER Capacity Aggregation Resources are being offered with the intention that the megawatt quantity that clears the auction is reasonably expected to be physically delivered through DER Capacity Aggregation Resource registration for the relevant Delivery Year. The DER Capacity Aggregation Resource Sell Offer Plan shall include all Existing DER Capacity Aggregation Resources and all Planned DER Capacity Aggregation Resources that the DER Aggregator intends to offer into an RPM Auction or include in an FRR Capacity Plan.

The DER Aggregator shall provide the details of, and key assumptions for underlying Component DER for the Planned DER Capacity Aggregation Resource contained in the Sell Offer Plan, including but not limited to:

(i) Nominated megawatt quantities and method(s) of achieving generation or load reductions to meet megawatt quantities

(ii) equipment and technology to be installed or controlled

(iii) plan and ability to acquire generating resources or load reductions at customer site(s) and assumptions regarding regulatory approval of program(s), if applicable

(iv) A measurement and verification plan developed in accordance with PJM Manuals, if applicable

(v) Zone and LDA information

(vi) A schedule of an approximate timeline for procuring Component DER

DER Aggregator Officer Certification Form.
Each DER Capacity Aggregation Resource Sell Offer Plan must include a DER Aggregator Officer Certification, signed by an officer of the DER Aggregator that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the DER Capacity Aggregation Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the DER Aggregator is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through the DER Capacity Aggregation Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement, and/or RAA.

The Unforced Capacity value of a DER Capacity Aggregation Resource will be determined as the sum of the Unforced Capacity value of the Component DER within a DER Aggregation Resource registered and linked to the DER Capacity Aggregation Resource, accounting for any co-located load that is not Station Power, in accordance with the provisions of the PJM Manuals.

The DER Aggregator shall provide Component DER within a DER Aggregation Resource registered and linked to a DER Capacity Aggregation Resource located within the same Zone and LDA as specified in its cleared sell offer, and may be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide Component DER within a DER Aggregation Resource registered and linked to the applicable DER Capacity Aggregation Resource in such location and quantity consistent with its cleared offer.

A DER Aggregator offering a Planned DER Capacity Aggregation Resource must comply with all applicable credit requirements, as set forth in Tariff, Attachment Q.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.

B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

SCHEDULE 8

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party that has not elected the FRR Alternative for such Delivery Year shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR

Where:

OPL = Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals, and as adjusted further to include the Obligation Peak Load associated with any Load Adjustment that may be allocated to the Party

Final Zonal RPM Scaling Factor = the factor determined as set forth in sections B and C of this Schedule

FPR = the Forecast Pool Requirement

Netting of Behind the Meter Generation for a Party with regard to Non-Retail Behind the Meter Generation shall be subject to the following limitation:

For the 2006/2007 Planning Period, 100 percent of the operating Non-Retail Behind the Meter Generation shall be netted, provided that the total amount of Non-Retail Behind the Meter Generation in the PJM Region does not exceed 1500 megawatts ("Non-Retail Threshold"). For each Planning Period/Delivery Year thereafter, the Non-Retail threshold shall be proportionately increased based on load growth in the PJM Region but shall not be greater than 3000 megawatts. Load growth shall be determined by the Office of the Interconnection based on the most recent forecasted weather-adjusted coincident summer peak for the PJM Region divided by the weather-adjusted coincident peak for the previous summer for the same area. After the load growth factor is applied, the Non-Retail Threshold will be rounded up or down to the nearest whole megawatt and the rounded number shall be the Non-Retail Threshold for the current Planning Period and the base amount for calculating the Non-Retail Threshold for the succeeding planning period. If the Non-Retail Threshold is exceeded, the amount of operating Non-Retail Behind the Meter Generation that a Party may net shall be adjusted according to the following formula:

Party Netting Credit = (NRT/ PJM NRBTMG) * Party Operating NRBTMG

Where: NRBTMG is Non-Retail Behind the Meter Generation

NRT is the Non-Retail Threshold

PJM NRBTMG is the total amount of Non-Retail Behind the Meter Generation in the PJM Region

The total amount of Non-Retail Behind the Meter Generation that is eligible for netting in the PJM Region is 3000 megawatts. Once this 3000 megawatt limit is reached, any additional Non-Retail Behind the Meter Generation which operates in the PJM Region will be ineligible for netting under this section.

In addition, the Party NRBTMG Netting Credit shall be adjusted pursuant to Schedule 16 of this Agreement, if applicable.

A Party shall be required to report to PJM such information as is required to facilitate the determination of its NRBTMG Netting Credit in accordance with the procedures set forth in the PJM Manuals.

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

Base Zonal Unforced Capacity Obligation = (ZPLDY/RPLDY) * RUCO

and

Base Zonal RPM Scaling Factor = Base Zonal Unforced Capacity Obligation / (Adjusted ZWNSP * FPR)

Where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Delivery Year

RPLDY = RTO Preliminary Peak Load Forecast for such Delivery Year,

RUCO = the RTO Unforced Capacity Obligation satisfied in the Base Residual Auction for such Delivery Year,

FPR – the Forecast Pool Requirement, and, Adjusted ZWNSP = Adjusted Zonal Weather Normalized Summer Peak = ZWNSP + [ZLA * (ZWNSP / (ZPLDY - ZLA))]

Where:

ZWNSP = Zonal Weather-Normalized Summer Peak for the summer season concluding four years prior to the commencement of such Delivery Year, and,

ZLA = the total zonal MW quantity of Load Adjustment for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Updated RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to each of the First, Second, and Third Incremental Auctions for such Delivery Year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones. In addition, for each Zone, PJM shall determine, as applicable, the Adjusted Zonal Weather Normalized Summer Peak as set forth in Section B of this Schedule, where the Obligation Peak Load associated with such Load Adjustment is included. The Obligation Peak Load associated with such Load Adjustment MW will be calculated for each "zone/area" as determined by:

LAOPL = the Obligation Peak Load associated with the total MW quantity of Load Adjustment of a Zone or separate wholesale area within the zone for such Delivery Year = LAMW * (ZWNSP / (ZPLDY - ZLA))

Where:

LAMW = the total MW quantity of Load Adjustment of a Zone or of a separate wholesale area within the Zone for the relevant Delivery Year,

ZWNSP = Zonal Weather-Normalized Summer Peak from most recent summer season,

ZPLDY = Zonal Peak Load Forecast for such Delivery Year, and,

ZLA = the total zonal MW quantity of Load Adjustment for such Delivery Year.

C. This subsection C is effective through the end of the 2024/2025 Delivery Year. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is decommitted in such auction. The Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction. The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year).

C1. This subsection C1 is effective beginning with the 2025/2026 Delivery Year. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is de-committed in such auction. The Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction. The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Adjusted Zonal Weather Normalized Summer Peak of such Delivery Year).

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Zonal Weather Normalized Summer Peak for such Zone to each "zone/area" in the Zone to determine the Obligation Peak Load for each "zone/area" in such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each Operating Day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. The Electric Distributor may submit corrections to the Obligation Peak Load data up to 12:00PM Eastern Prevailing Time of the next Business Day following the Operating Day.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a given "zone/area" within the Zone must equal the Obligation Peak Load established for that "zone/area," including any Load Adjustment MW, determined as set forth in section B above.

SCHEDULE 8.1

FIXED RESOURCE REQUIREMENT ALTERNATIVE

The Fixed Resource Requirement (“FRR”) Alternative

A. The Fixed Resource Requirement (“FRR”) Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

B. Eligibility

1. A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources and Seasonal Capacity Performance Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through the 2028/2029 Delivery Year.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the Base Zonal FRR Scaling Factor times the summation of the FRR Entity's MW share of the Zonal Weather Normalized Summer Peak last determined prior to the Base Residual Auction for such Delivery Year plus the Obligation Peak Load MW associated with any Load Adjustment specified for such Delivery Year for any "zone/area" served by the FRR Entity's Capacity Plan. The Obligation Peak Load MW associated with a Load Adjustment specified for a "zonal/area" is determined as set forth in RAA, Schedule 8, section B.

The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal [(ZPLDY-ZLA) / ZWNSP], where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year;

ZLA = the Zonal MW quantity of Load Adjustment for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form

shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, an FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. For

Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource MWs that are committed to RPM for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any uncommitted Capacity Resource MWs for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Tariff, Attachment DD for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), subject to the limitations described in RAA, Schedule 8.1, section D, subsection D.2, or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to RAA, Schedule 8.1, section B, subsection B.2 that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party's expected Daily Unforced Capacity Obligation under RAA, Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party's total expected Unforced Capacity obligation (under both RAA, Schedule 8 and RAA, Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. This subsection 1 is effective through the 2024/2025 Delivery Year. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as:

> the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

1A. This subsection 1A is effective beginning with the 2025/2026 Delivery Year. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL = Obligation Peak Load, defined as:

the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals, and as adjusted further to include the Obligation Peak Load associated with any Load Adjustment that may be allocated to “zone/area”;

Final Zonal FRR Scaling Factor = [FZPLDY - FZLA] / FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZLA = Final Zonal MW quantity of Load Adjustment for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Through the 2024/2025 Delivery Year, such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions). Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, such FRR Capacity Deficiency Charge shall equal the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times the price level corresponding to Point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the Locational Deliverability Area encompassing the Zone of the FRR Entity.

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall pay a Locational Reliability Charge for the acquired load.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining the RTO/LDA Reliability Requirements, and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

I. Savings Clause for State-Wide FRR Program

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and El05-148, the PJM Tariff and this Agreement. Each LSE subject to such state action shall become a Party to this Agreement and shall be deemed to have elected the FRR Alternative.

SCHEDULE 8.1 – Appendix
OHIO POWER COMPANY
FRR CAPACITY RATE

The Public Utilities Commission of Ohio (PUCO) in Case No. 10-2929-EL-UNC on July 2, 2012, issued an order approving a state compensation mechanism for load of alternative retail LSEs (a/k/a Competitive Retail Electric Service (CRES) providers) in Ohio Power Company's FRR Service Area for FRR capacity made available by Ohio Power Company under the RAA, effective as of August 8, 2012. For purposes of administering the state compensation mechanism, the wholesale rate shall be equal to the adjusted final zonal PJM RPM rate in effect for the rest of the RTO region for the current PJM delivery year, and with the rate changing annually on June 1, 2013, and June 1, 2014, to match the then current adjusted final zonal PJM RPM rate in the rest of the RTO region. The Final Zonal Capacity Price will be the price applicable to the unconstrained region of PJM adjusted for the RPM Scaling Factor, the Forecast Pool Requirement and Losses.

Schedule 8.1 – Appendix 2A

Appalachian Power Company (APCO)

CAPACITY COMPENSATION FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

The definitions and provisions contained in this Appendix 2A shall be applicable only to the provisions of Schedule 8.1 - Appendix 2A, unless otherwise specified.

"Capacity Rate" means the result produced by populating the Capacity Compensation Formula Rate Template with data to calculate the Fixed Resource Requirement capacity rate for load served by Virginia Competitive Service Providers ("CSPs").

"Annual Review Procedures" means the procedures pursuant to which an Interested Party may review the Annual Update and notify APCO of any specific challenges to the Annual Update.

"Annual Update" means the posting and informational filing submitted by APCO on or before May 25 of each year that sets forth the capacity rate for the subsequent Rate Year.

"Capacity Compensation Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Schedule 8.1 – Appendix 2B under Section D.8 of Schedule 8.1 of the PJM Interconnection, L.L.C. ("PJM") Reliability Assurance Agreement ("RAA").

"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.

"Material Changes" means (i) material changes in APCO's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate template to be different from the result under the Formula Rate Template as calculated without such change.

"Partial Rate Year" means the period February 9, 2013 through May 31, 2013.

"Partial Rate Year Effective Date" means February 9, 2013.

"Protocols" means these Capacity Compensation Formula Rate Implementation Protocols.

"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1 below.

"Rate Year" means the twelve consecutive month period that begins on June 1 and continues through May 31 of the subsequent calendar year.

"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2 below.

Section 1 Annual Updates

a. The Capacity Rate for the Partial Rate Year shall become effective on the Partial Rate Year Effective Date and such Capacity Rate shall not be subject to the Protocols. Beginning June 1, 2013, the Capacity Rate shall be revised in accordance with the Capacity Compensation Formula Rate Template, and the Annual Update for the Rate Year beginning on June 1, 2013, and all subsequent Rate Years, shall be fully subject to the Protocols.

b. On or before May 25 of 2013 and each year thereafter, APCO shall recalculate its Capacity Rate, producing the Annual Update for the upcoming Rate Year, and shall post such Annual Update, in both PDF and working Excel spreadsheet versions, on PJM's Internet website. In addition, APCO shall submit such Annual Update as an informational filing with FERC. APCO will also post such Annual Update on APCO's Internet website at https://www.appalachianpower.com/service/choice/

c. The date as provided in Section 1.b shall be that Rate Year's Publication Date.

d. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

e. The Annual Update shall include a workable Excel file or files containing the data-populated Formula Rate Template as well as supporting calculations and workpapers that demonstrate and explain information not otherwise set out in APCO's FERC Form No. 1 reports. [1]

[1] It is the intent that each input to the Formula Rate Template will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet appurtenant to the filed Formula Rate Template, the inputs to the worksheet will meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate Template.

f. The Annual Update for the Rate Year:

(i) Shall, to the extent specified in the Formula Rate Template, be based upon prudently incurred costs; the data for such prudently incurred costs will be taken from APCO's FERC Form No. 1 for the most recent calendar year, and will be based upon the books and records of APCO (all of the foregoing data, books, and records maintained consistent with the USofA and FERC accounting policies, practices, and procedures);

(ii) Shall be populated, in accordance with FERC's orders establishing generally applicable ratemaking policies and the Formula Rate Template, with the data identified above;

(iii) Shall be subject to the Annual Review Procedures set forth in these Protocols; and

(iv) Shall disclose any change in accounting during the rate period that affects inputs to the formula rate or the resulting charges billed under the formula rate and, in particular, include the following:

(a) Disclose: (1) the initial implementation of an accounting standard or policy; (2) the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction; (3) corrections of errors and prior period adjustments; (4) the implementation of new estimation methods or policies that change prior estimates; and (5) changes to income tax elections.

(b) Identify items included in the formula rate at an amount other than on a historical cost basis, e.g., fair value adjustments.

(c) Identify any reorganization or merger transaction and explain the effect of the accounting for such transactions on inputs to the formula rate.

(d) To the extent these accounting changes and other matters affect APCO's inputs to its formula rate, APCO will provide a narrative explanation of how such changes affect those items on charges billed under the formula rate.

g. Formula Rate Inputs

(i) Stated inputs to the Formula Rate Template: rate of return on common equity; Post Employment Benefits other Than Pensions ("PBOPs"); and depreciation and amortization rates shall be stated values to be used in the

Formula Rate Template until changed pursuant to an FPA Section 205 or 206 filing.

(ii) Cost of Service elements recorded in accounts not specifically provided for in the Capacity Rate: any cost, expense or other element of the cost of providing service not specifically provided for shall not be recoverable under the Formula Rate until filed for pursuant to FPA Section 205, accepted by FERC and, if otherwise required, a determination has been made by the Office of the Chief Accountant regarding the journal entries for the transaction.

(iii) The Formula Rate Template refers to certain pages and line numbers found in APCO's FERC Form 1 used for reporting calendar year 2011 data. From time to time, FERC may make changes in the format of the FERC Form 1, and such changes may result in certain page and line references included in Formula Rate Template being rendered inaccurate. To the extent that only formatting changes are involved and there is no substantive change, the Formula Rate Template shall be interpreted as if the page and line references contained therein are references to the pages and lines contained in the current FERC Form 1 on which can be found the data described on the pages and lines of the prior FERC Form 1. Such changes in references shall be noted and new references stated in the formula and submitted to FERC in a limited Section 205 filing.

Section 2 **<u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. No later than ten (10) days after the Publication Date, APCO will post the Annual Update on its website dedicated to Virginia Competitive Service Providers ("CSPs") and inform CSPs that they will have ten (10) days to request that APCO schedule an open meeting to discuss the Annual Update. If APCO receives one or more requests within such 10-day period, APCO will schedule an open meeting within thirty (30) days of such request(s). APCO shall provide at the meeting an item-by-item description of the major cost drivers for the change in rates, and an opportunity to discuss these items.

b. Interested Parties shall have up to one hundred ten (110) days after the Publication Date ("Review Period") (unless such period is extended with the written consent of APCO) to review the calculations and to notify APCO in writing of any specific challenges, including challenges related to any Material Changes, to the application of the Formula Rate in an Annual Update ("Preliminary Challenge").

c. Interested Parties shall have the right to serve reasonable information requests on APCO up to ninety (90) days after the Publication Date. Such information requests shall be limited to what is necessary to determine: (i) whether APCO has properly calculated the Annual Update under review (including any corrections pursuant to

Section 4); (ii) whether APCO has correctly applied the Formula Rate Template; (iii) whether the inputs to the Formula Rate Template are appropriate costs and revenue credits; and (iv) whether the inputs are just and reasonable. Interested Persons can make information requests regarding allocation methodologies, including inter-corporate cost allocation methodologies, used to derive the inputs. Interested Parties may request accounting practices to the extent they impact the determination of the annual revenue requirement. They may also request information on procurement methods and cost control methodologies used by APCO.

d. APCO shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by APCO up to seventy-five (75) days after the Publication Date for which APCO is unable to provide a response before the end of the Review Period, the Review Period shall be extended day-for-day until APCO's response is provided.

e. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Annual Update. Failure to make a Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update, but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such challenge affects the subsequent Annual Update.

f. In any proceeding initiated to address a Preliminary or Formal Challenge or sua sponte by FERC, a party or parties seeking to modify the Formula Rate Template in any respect shall bear the applicable burden under the Federal Power Act ("FPA"). Nothing in the protocols changes the burden of proof imposed under the FPA.

Section 3 <u>Resolution of Challenges</u>

a. If APCO and any Interested Parties have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period ends, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of APCO to continue efforts to resolve the Preliminary Challenge) to submit a written Formal Challenge to FERC, pursuant to 18 C.F.R. § 385.206, which shall be served on APCO by electronic service on the date of such filing ("Formal Challenge"). However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if FERC already has initiated a proceeding to consider the Annual Update.

b. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify APCO of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issue in a Preliminary Challenge or Formal Challenge.

c. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before any court to review a FERC decision.

d. Any response by APCO to a Formal Challenge must be submitted to FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party or parties by electronic service on the date of such filing.

e. APCO shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate Template, and the applicable procedures in these Protocols, and of proving that it has properly calculated the challenged Annual Update pursuant to the Formula Rate Template, and of proving it has reasonably adopted and applied any Material Changes in that year's Annual Update.

f. These Protocols in no way limit the rights of APCO or any Interested Party to initiate a proceeding at FERC at any time with respect to the Formula Rate Template or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and FERC's regulations.

g. It is recognized that resolution of Formal Challenges concerning Material Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update, or changes to the Formula Rate Template to ensure that the Formula Rate Template continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 4 **<u>Changes to Annual Informational Filings</u>**

a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of APCO, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, or as the result of any FERC proceeding to consider a prior year's Annual Update, APCO shall promptly notify the Interested Parties, file a correction to the Annual Update with FERC as an amended informational filing describing the change(s) and the cost impact.

b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.

c. Changes Made During the Review Period. Unless otherwise agreed by APCO and the Interested Parties, a correction made under Section 4.a prior to the time determined for the filing of a Formal Challenge shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Parties to review the Annual Update, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the review of the Annual Update shall then be limited to the aspects of the Formula Rate Template affected by the corrections.

Schedule 8.1 – Appendix 2B
Appalachian Power Company
Capacity Compensation Formula Rate

Appendix 2
Page 1

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CAPACITY RATE
12 Months Ending 12/31/####

	RATE $/MW/Day (1)	CAPACITY MW (2)	Amount $ (1) x (2) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$	#	$

Note A: Rate will be applied to peak obligation demands at or adjusted to generation level (including losses).

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DETERMINATION OF CAPACITY RATE
12 Months Ending 12/31/####

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(APCo 5 CP Demand/365) (Note A)}}$$

$$\frac{\$}{\#\qquad /365} = \qquad \$$$

Where: Annual Production Fixed Cost, P.4, L.8.

Note A: Average of demand at time of PJM five highest daily peaks. – See Workpaper 1.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/####

		Reference (1)	Production Amount (2)
1.	GSU & Associated Investment	Note A	$
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	$
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$
5.	GSU Related Depreciation Expense	L.3 x L.4	$
6.	Station Equipment Acct. 353 Investment	Note B	$
7.	Percent (GSU to Acct. 353)	L.1 / L.6	%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$
9.	GSU & Associated Investment O&M	L.7 x L.8	$

Note A: See Workpaper 16
Note B: See Workpaper 17

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/####

		Reference	PRODUCTION Amount
		(1)	(2)
1.	Return on Rate Base	P.5, L.18, Col.(2)	$
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$
3.	Depreciation Expense	P.16, L.9, Col.(2); Note A	$
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(3)	$
5.	Income Tax	P.18, L.5, Col.(2)	$
6.	Sales for Resale	Note B	$
7.	Sales for Resale (Energy Credit)	Note C	$
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$

Note A: See page 20 for depreciation rates by plant account.

Note B: Capacity related revenues associated with sales as reported in Account 447 (includes pool capacity demand). See Workpaper 15d.

Note C: Workpaper 15d

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RETURN ON PRODUCTION-RELATED INVESTMENT
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	ELECTRIC PLANT				
2.	Gross Plant in Service	P.6, L.4, Col.(2)-(4)	$	$	$
3.	Less: Accumulated Depreciation	P.6, L.11, Col.(2)-(4)	$	$	$
4.	Net Plant in Service	L.2 - L.3	$	$	$
5.	Less: Accumulated Deferred Taxes	P.6, L.12, Col.(2)-(4)	$	$	$
6.	Plant Held for Future Use (Note A)	FF1, P.214	$	$	$
7.	Subtotal - Electric Plant	L.4 - L.5 + L.6	$	$	$
	WORKING CAPITAL				
8.	Materials & Supplies				
9.	Fuel	P.9, L.2, Col.(2)-(4)	$	$	$
10.	Nonfuel	P.9, L.8, Col.(2)-(4)	$	$	$
11.	Total M & S	L.9 + L.10	$	$	$
12.	Prepayments Nonlabor (Note B)		$	$	$
13.	Prepayments Labor (Note B)		$	$	$
14.	Prepayments Total (Note B)	L.12 + L.13	$	$	$
15.	Cash Working Capital	P.8, L.7, Col.(1)-(3)	$	$	$
16.	Total Rate Base	L.7 + L.11 + L.14 + L.15	$	$	$
17.	Weighted Cost of Capital	P.11, L.4, Col.(4)	%	%	%
18.	Return on Rate Base	L.16 x L.17	$	$	$

Note A: Workpaper 19

Note B: WP-5c Prepayments include amounts booked to Account 165. Nonlabor related prepayments allocated to the production function based on gross plant on P.6, L.7. Labor related prepayments allocated to production function based on wages and salaries on P.7, Note B.

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
12 Months Ending 12/31/####

		System			PRODUCTION		
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1.	GROSS PLANT IN SERVICE (Note A)						
2.	Plant in Service (Note C)	Line 16	$	Line 16	$	$	$
3.	Allocated General & Intangible Plant			P.7, Col(3)-(5), L.25	$	$	$
4.	Total	L.2 + L.3	$		$	$	$
		Note A				%	%
5.				Col.(2), L.4	$	$	$
6.				Col.(1), L.4	$	$	$
7.	General & Intangible Plant Allocator		%	L.5/L.6	%	%	%
8.	ACCUMULATED PROVISION FOR DEPRECIATION (Note A)						
9.	Plant in Service (Note D)	Line 20	$	Line 20	$	$	$
10.	Allocated General Plant		$	Note B	$	$	$
11.	Total	L.9 + L.10			$	$	$
12.	ACCUMULATED DEFERRED TAXES (Note A)	(Note E)	$	P.6a, L.52	$	$	$

Note A: Excludes ARO amounts.
Note B: (% From P.7, Col.(3), L.29)
Note C: Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts
Note D: Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.
Note E: WP8a, WP8ai

GSU DETAILS (Lns 2 and 9 above)

					PRODUCTION		
		Reference	Amounts (1)	Reference	Amount (2)	Demand(3)	Energy (4)
13.	GROSS PLANT IN SERVICE						
14.	Plant in Service (Note C)	WP6a. L.11	$	WP6a. L.11	$	$	$
15.	GUS Plant in Service (Note C)	P.3 L.1, Col (2)			$	$	$
16.	Total Plant in Service (Note C_	L.14 + L.15			$	$	$
17.	ACCUMULATED PROVISION FOR DEPRECIATION						
18.	Accumulated Prov. For Depreciations (Note D)	WP6b, L.7	$	WP6b	$	$	$
19.	GSU Accumulated Prov. Depreciation (Note D)	WP16			$	$	$
20	Total Accumulated Depreciation (Note D)	L.18 + L.19			$	$	$

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APPALACHIAN POWER COMPANY
BLANK FORMUAL RATE TEMPLATE
PRODUCTION RELATED ADIT
12 Months Ending 12/31/####

	Account	Description	Year End Balance	Exclusions	100% Production (Energy Related)	100% Production (Demand Related)	Labor
1.	190	Excluded Items	$	$			
2.	190	100% Production (Energy)	$		$		
3.	190	100% Production (Demand)	$			$	
4.	190	Labor Related	$				$
5.	190	Total	$	$	$	$	$
6.		Production Allocation		%	%	%	%
7.		(Gross Plant or Wages/Salaries)		$	$	$	$
8.		Demand Related			$	$	$
9.		Energy Related			$	$	$
10.		Note A			Direct	Direct	P.7, Note B
11.	281	Excluded Items	$	$			
12.	281	100% Production (Energy)	$		$		
13.	281	100% Production (Demand)	$			$	
14.	281	Labor Related	$				$
15.	281	Total	$	$	$	$	$
16.		Production Allocation		%	%	%	%
17.		(Gross Plant or Wages/Salaries)		$	$	$	$
18.		Demand Related			$	$	$
19.		Energy Related			$	$	$
20.		Allocation Basis			Direct	Direct	P.7, Note B
21.	282	Excluded Items	$	$			
22.	282	100% Production (Energy)	$		$		
23.	282	100% Production (Demand)	$			$	
24.	282	Labor Related	$				$
25.	282	Total	$	$	$	$	$
26.		Production Allocation		%	%	%	%
27.		(Gross Plant or Wages/Salaries)		$	$	$	$
28.		Demand Related			$	$	$
29.		Energy Related			$	$	$
30.		Allocation Basis			Direct	Direct	P.7, Note B
31.	283	Excluded Items	$	$			
32.	283	100% Production (Energy)	$		$		
33.	283	100% Production (Demand)	$			$	
34.	283	Labor Related	$				$
35.	283	Total	$	$	$	$	$
36.	283	Production Allocation		%	%	%	%
37.		(Gross Plant or Wages/Salaries)		$	$	$	$
38.		Demand Related			$	$	$
39.		Energy Related			$	$	$
40.		Allocation Basis			Direct	Direct	P.7, Note B
41.	255	Excluded Items	$	$			
42.	255	100% Production (Energy)	$		$		
43.	255	100% Production (Demand)	$			$	
44.	255	Labor Related	$				$
45.	255	Total	$	$	$	$	$
46.	255	Production Allocation		%	%	%	%
47.		(Gross Plant or Wages/Salaries)		$	$	$	$

	Summary Production Related ADIT	Total	Demand	Energy
48.				
49.	P Plant (Energy Related)	$	$	$
50.	P Plant (Demand Related)	$	$	$
51.	Labor Related	$	$	$
52	Total	$	$	$

Source: Functionalized balances for Accounts 190, 281, 282, 283 and 255 from WP-8a and 8ai.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED GENERAL PLANT ALLOCATION
12 Months Ending 12/31/####

	Total System (Note A)	Allocation Factor	General Plant Accounts 101 and 106 Related to Production (1) x (2)	Demand	Energy	FERC Form 1 Reference
1. GENERAL PLANT	(1)	(2)	(3)	(4)	(5)	
2						
3. Land	$	Note B	$	$	$	
4. General Offices	$		$	$	$	
5. Total Land	$		$	$	$	P207 L86 Col (g)
6		%				
7. Structures	$	Note B	$	$	$	
8. General Offices	$		$	$	$	
9. Total Structures	$		$	$	$	P207 L87 Col (g)
10		%				
11. Office Equipment	$	Note B	$	$	$	
12. General Offices			$	$	$	
13. Total Office Equipment	$		$	$	$	P207 L88 Col (g)
14. Transportation Equipment	$	Note B	$	$	$	P207 L89 Col (g)
15. Stores Equipment	$	Note B	$	$	$	P207 L90 Col (g)
16. Tools, Shop & Garage Equipment	$	Note B	$	$	$	P207 L91& L93 Col (g)
17. Lab Equipment	$	Note B	$	$	$	P207 L92 Col (g)
18. Communications Equipment	$	Note B	$	$	$	P207 L94 Col (g)
19. Miscellaneous Equipment	$	Note B	$	$	$	P207 L95 Col (g)
20. Subtotal General Plant	$		$	$	$	P207 L96 Col (g)
21. PERCENT		Note C	%	%	%	
22. Other Tangible Property		Note D	$	$	$	P207 L97 Col (g)
23. TOTAL GENERAL PLANT	$		$	$	$	
24. INTANGIBLE PLANT	$	Note B	$	$	$	P205 L5 Col (g)
25. TOTAL GENERAL AND INTANGIBLE	$		$	$	$	L23 + L.24
26. PERCENT		Note E	%	%	%	

NOTE A: See Workpaper 6c.

NOTE B: Allocation factors based on wages and salaries in electric operations and maintenance expenses excluding administrative and general expenses:

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27 (see workpaper 9a).	$
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20. (see WP-9a)	$
c. Ratio (b / a)	%

NOTE C: L.20, Col.(3) / L.20, Col.(1)

NOTE D: Directly assigned to Production

NOTE E: L.28, Col.(3) / L.28, Col.(1)

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED CASH REQUIREMENT
12 Months Ending 12/31/####

			PRODUCTION	
	Reference	Amount	Demand	Energy
		(1)	(2)	(3)
1. Total Production Expense Excluding Fuel Used In Electric Generation	P.14, L.12 Col.(1)-(3)	$	$	$
2. Less Fuel Handling / Sale of Fly Ash	P.14, L.1 thru L.3,Col. (1)-(3)	$	$	$
3. Less Purchased Power	P.14, L.11, Col.(1)-(3)	$	$	$
4. Other Production O&M	Sum (L.1 thru L.3)	$	$	$
5. Allocated A&G	P.10, L.17, Col.(3)-(5)	$	$	$
6. Total O&M for Cash Working Capital Calculation	L.4 + L.5	$	$	$
7. O&M Cash Requirements	=45 / 360 x L.6	$	$	$

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED MATERIALS & SUPPLIES
12 Months Ending 12/31/####

	SYSTEM		PRODUCTION			
	Reference	Amount	Reference	Amount	Demand	Energy
1. Material & Supplies (Note A)		(1)		(2)	(3)	(4)
2. Fuel (Note C)	FF1, P.110, L.,45,46 Workpapers WP-5b	$		$	$	$
3. Non-Fuel						
4. Production	Note D	$	100% Col. 1	$	$	$
5. Transmission		$	0	$	$	$
6. Distribution		$	0	$	$	$
7. General		$	Note B	$	$	$
8. Total	L.4 + L.5 + L.6 + L.7	$		$	$	$
9. Account 158 Allowances	Note D	$		$	$	$

Note A: Year end balance
Note B: Column (1) times % from P.7, Col.(3), L.26.
Note C: See Workpaper 5b.
Note D: See Workpaper 5a.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
12 Months Ending 12/31/####

		Account	Reference	System Amount (1)	Alllocation Factor % (2)	Production Amount (3)	Demand (4)	Energy (5)	FERC Form 1 Reference
1.	ADMINISTRATIVE & GENERAL EXPENSE								
2.	RELATED TO WAGES AND SALARIES								
3.	A&G Salaries	920	WP 10a	$					P323 L181 Col (b)
4.	Outside Services	923	WP 10a	$					P323 L 184 Col (b)
5.	Employee Pensions & Benefits	926	WP 10a	$	Note F				P323 L187 Col (b)
6.	Office Supplies	921	WP 10a	$					P323 L182 Col (b)
7.	Injuries & Damages	925	WP 10a	$					P323 L186 Col (b)
8.	Franchise Requirements	927	WP 10a	$					P323 L188 Col (b)
9.	Duplicate Charges - Cr.	929	WP 10a	$					P323 L190 Col (b)
10.	Total		Ls. 3 thru 9	$	Note A	$	$	$	
11.	Miscellaneous General Expense	930	WP 10a	$	Note A, C & D	$	$	$	P323 L192 Col (b)
12.	Adm. Expense Transfer – CR	922	WP 10a	$	Note B	$	$	$	P323 L183 Col (b)
13.	Property Insurance	924	WP 10a	$	Note E	$	$	$	P323 L185 Col (b)
14.	Regulatory Comm. Expenses	928	WP 10a	$	Note C	$	$	$	P323 L189 Col (b)
15.	Rents	931	WP 10a	$	Note B	$	$	$	P323 L193 Col (b)
16.	Maintenance of General Plant	935	WP 10a	$	Note B	$	$	$	P323 L196 Col (b)
17.	TOTAL A & G EXPENSE		L.10 thru 16	$		$	$	$	

Note A: % from Note B, P.7
Note B: General Plant % from P.7, Col.(3), L.26
Note C: See Workpaper 11. Excludes all items not related to wholesale service and also excludes FERC assessment of annual charges.
Note D: Excludes general advertising and company dues and memberships.
Note E: % Plant from P.6, L.7.
Note F: PBOP expense is fixed at $6,222,780. This amount cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPOSITE COST OF CAPITAL
12 Months Ending 12/31/####

			Total Company Capitalization	Weighted Cost Ratios		Cost of Capital	Weighted Cost of Capital
		Reference	$	%	Reference	%	(2 x 3)
			(1)	(2)		(3)	(4)
1.	Long Term Debt	Note A	$	%	Note D	%	%
2.	Preferred Stock	Note B	$	%	Note E	%	%
3.	Common Stock	Note C	$	%	Note F	10.4%	%
4.	Total	L1 + L2 + L3	$	%			%

Note A: P.12, L.5, Col.1.

Note B: P.13a, L.4 Col. (2).

Note C: P.13b, L.5.Col (2)

Note D: P.12, L.16, Col. (2).

Note E: P.13a. L.4, Col (2)

Note F: Return on equity cannot be changed absent a Section 205/206 filing with the Commission.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT
12 Months Ending 12/31/####

		Reference	Debt Balance	Interest & Cost Booked
			(1)	(2)
	12 Months Ending 12/31/2009 (Actual)			
1.	Bonds (Acc 221)	FF1, 112.18.c.	$	
2.	Less: Reacquired Bonds (Acc 222)	FF1, 112.19.c.	$	
3.	Advances from Assoc Companies (Acc 223)	FF1, 112.20.c.	$	
4.	Other Long Term Debt (Acc 224)	FF1, 112.21.c.	$	
5.	Total Long Term Debt Balance		$	
	Costs and Expenses (actual)			
6.	Interest Expense (Acc 427)	FF1, 117.62.c.	Note A	$
7.	Amortization Debt Discount and Expense (Acc 428)	FF1, 117.63.c.		$
8.	Amortization Loss on Reacquired Debt (Acc 428.1)	FF1, 117.64.c.		$
9.	Less: Amortiz Premium on Reacquired Debt (Acc 429)	FF1, 117.65.c.		$
10.	Less: Amortiz Gain on Reacquired Debt (Acc 429.1)	FF1, 117.66.c.		$
11.	Interest on LTD Assoc Companies (portion Acc 430)	Workpaper-13, L.7	Note A	$
12.	Sub-total Costs and Expense			$
13.	Less: Total Hedge (Gain) / Loss	P. 12a, L. 11, Col. (6)		$
14.	Plus: Allowed Hedge Recovery	P. 12a, L. 15, Col. (6)		$
15.	Total LTD Cost Amount	L. 12 - L. 13 + L. 14		$
16.	Embedded Cost of Long Term Debt = L.15, Col.(2) / L. 5, Col.(1)			%

Note A: Reconciliation of Interest Expense to FF1, pg 257, Ln 33 Col (1)

Ln 6 Interest Expense (Acc 427)	$
Ln 11 Interest on LTD Assoc Companies (portion Acc 430)	$
FF1, pg 257, Ln 33 Col (i)	$

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
LONG TERM DEBT Limit on Hedging (Gain)/Loss on Interest Rate Derivatives of LTD
12 Months Ending 12/31/####

		(1)	(2)	(3)	(4)	(5)	(6)
				Net Includable			
	HEDGE AMT BY ISSUANCE	Total Hedge	Excludable	Hedge Amount	Unamortized	Amortization Period	
	FERC Form 1, p. 256-257 (i)	(Gain) / Loss	Amounts (Note A)	Subject to Limit	Balance	Beginning	Ending
1.	Debt Issuance #1	$	$	$	$		
2.	Debt Issuance #2	$	$	$	$		
3.	Debt Issuance #3	$	$	$	$		
4.	Total Hedge Amortization	$	$	$			
	Limit on Hedging (G)/L on Interest Rate Derivatives of LTD						
5.	Hedge (Gain) / Loss prior to Application of Recovery Limit						%
	Enter a hedge Gain as a negative value and a hedge Loss as a positive value						
6.	Total Capitalization			Page11, L.4, col.(1)		$	
7.	5 basis point Limit on (G)/L Recovery						#
8.	Amount of (G)/L Recovery Limit			L. 12 * L.13			$
9.	Hedge (Gain) / Loss Recovery (Lesser of Line 5 or Line 8)						$
	To be subtracted or added to actual Interest Expenses on Page 12, Line 14						

Note A: Annual amortization of net gains or net loss on interest rate derivative hedges on long term debt shall not cause the composite after-tax weighted average cost of capital to increase/decrease by more than 5 basis points. Hedge gains/losses shall be amortized over the life of the related debt issuance. The unamortized balance of the g/l shall remain in Acc 219 Other Comprehensive Income and shall not flow through the rate calculation. Hedge-related ADIT shall not flow through rate base. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this calculation and are to be recorded above.

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APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PREFERRED STOCK
12 Months Ending 12/31/####

			(1) Reference	(2) Amount
1.	Preferred Stock Dividends		FF1, P.118, L.29	$
2.	Preferred Stock Outstanding	Note A & B	FF1, P.251, L. 9 (f)	$
3.	Plus: Premium on Preferred Stock	Note A	FF1, P.112, L.6	$
4.	Total Preferred Stock		L.2 + L.3	$
5.	Average Cost Rate		L.1 / L.4	%

Note A: Workpaper -12b.

Note B: Preferred stock outstanding excludes pledged and Reacquired (Treasury) preferred stock.

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Page 13b

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMMON EQUITY
12 Months Ending 12/31/####

		(1) Source	(2) Balances
1.	Total Proprietary Capital	WP-12a,L. 1 col. a	$
	Less:		
2.	Preferred Stock (Acc 204, pfd portion of Acc 207-213)	WP-12a, L 1 col.b+c+d	$
3.	Unappropriated Undistributed Subsidiary Earnings (Acc 216.1)	WP-12a, L.1, col.e	$
4.	Accumulated Comprehensive Other Income (Acc 219)	WP-12a, L.1, col.f	$
5.	Total Balance of Common Equity	L.1-2-3-4	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/####

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)	FERC Form 1 Reference
1. Coal Handling	501.xx	$	$	$	P320 L5 Col (b) [Note D]
2. Lignite Handling	501.xx	$	$	$	P320 L5 Col (b) [Note D]
3. Sale of Fly Ash (Revenue & Expense)	501.xx	$	$	$	P320 L5 Col (b) [Note D]
4. Rents	507	$	$	$	P320 L11 Col (b)
5. Hydro O & M Expenses	535-545	$	$	$	P320 L.44-L.49 Col (b) P320 L.53-L.57 Col (b)
6. Other Production Expenses	557	$	$	$	P321, L.78 Col (b)
7. System Control of Load Dispatching	Note C	$	$	$	P321, L77., L88., L92., P322, L.121, Col (b)
8. Other Steam Expenses	Note A	$	$	$	
9. Combustion Turbine	Note A	$	$	$	
10. Nuclear Power Expense-Other	Note A	$	$	$	
11. Purchased Power	555	$	$	$	P321 L76 Col (b)
12. Total Production Expense Excluding Fuel Used In Electric Generation above	Sum of L.1 – L.11	$	$	$	
13. A & G Expense P.10, L.17		$	$	$	
14. Generator Step Up related O&M	Note B	$	$	$	
15. Total O & M		$	$	$	

NOTE A: Amounts recorded in O&M Expense Accounts classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8, and 575.7.

NOTE D: Subaccount details of FF1 Accounts from Company's books and records

Reconciliation of System Control of Load Dispatching	
System Control and Load Dispatching	$
Scheduling, System Control	$
Reliability Planning and Standards Dev	$
Market Facilitation, Monitoring and Compliance	$
Ln 7, Pg 14	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
CLASSIFICATION OF FIXED AND VARIABLE PRODUCTION EXPENSES

Line No.	Description	FERC Account No.	Energy Related	Demand Related
1	POWER PRODUCTION EXPENSES			
2	Steam Power Generation			
3	Operation supervision and engineering	500	-	Xx
4	Fuel	501	Xx	-
5	Steam expenses	502	-	Xx
6	Steam from other sources	503	Xx	-
7	Steam transferred-Cr.	504	Xx	-
8	Electric expenses	505	-	Xx
9	Miscellaneous steam power expenses	506	-	Xx
10	Rents	507	-	Xx
11	Allowances	509	Xx	-
12	Maintenance supervision and engineering	510	Xx	-
13	Maintenance of structures	511	-	Xx
14	Maintenance of boiler plant	512	Xx	-
15	Maintenance of electric plant	513	Xx	-
16	Maintenance of miscellaneous steam plant	514	-	Xx
17	Total steam power generation expenses			
18	Nuclear Power			
19	Operation supervision and engineering	517		Xx
20	Coolants and Water	519		Xx
21	Steam Expenses	520		Xx
22	Steam from other sources	521		Xx
23	Less: ; Steam Transferred	522		Xx
24	Electric Expenses	523		Xx
25	Miscellaneous Nuclear Power Expense	524		Xx
26	Rents	525		Xx
27	Maintenance supervision and engineering	528	Xx	
28	Maintenance of structures	529		Xx
29	Maintenance of Reactor Plant Equip	530	Xx	
30	Maintenance of electric plant	531	Xx	
31	Maintenance of Misc Nuclear Plant	532	Xx	
32	Total power production expenses Nuclear			
33	Hydraulic Power Generation			
34	Operation supervision and engineering	535	-	Xx
35	Water for power	536	-	Xx
36	Hydraulic expenses	537	-	Xx
37	Electric expenses	538	-	Xx
38	Misc. hydraulic power generation expenses	539	-	Xx
39	Rents	540	-	Xx
40	Maintenance supervision and engineering	541	-	Xx
41	Maintenance of structures	542	-	Xx
42	Maintenance of reservoirs, dams and waterways	543	-	xx
43	Maintenance of electric plant	544	Xx	-
44	Maintenance of miscellaneous hydraulic plant	545	-	xx
45	Total hydraulic power generation expenses			
46	Other Power Generation			
47	Operation supervision and engineering	546	-	xx

Line No.	Description	FERC Account No.	Energy Related	Demand Related
48	Fuel	547	Xx	-
49	Generation expenses	548	-	Xx
50	Miscellaneous other power generation expenses	549	-	xx
51	Rents	550	-	xx
52	Maintenance supervision and engineering	551	-	xx
53	Maintenance of structures	552	-	xx
54	Maintenance of generation and electric plant	553	-	xx
55	Maintenance of misc. other power generation plant	554	-	xx
56	Total other power generation expenses			
57	Other Power Supply Expenses			
58	Purchased power	555	Xx	xx
59	System control and load dispatching	556	-	xx
60	Other expenses	557	-	xx
61	Station equipment operation expense (Note A)	562	-	xx
62	Station equipment maintenance expense (Note A)	570	-	xx

Note A: Restricted to expenses related to Generator Step-up Transformers and Other Generator related expenses.
See Note D, Page 6

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED DEPRECIATION EXPENSE
12 Months Ending 12/31/####

		Depreciation Expense (1)	Demand (2)	Energy (3)
	PRODUCTION PLANT			
	Depreciation and Amortization			
1.	Steam	$	$	$
2.	Nuclear	$	$	$
3.	Hydro – Conventional	$	$	$
4.	Hydro – Pump Storage l	$	$	$
5.	Int. Comb.	$	$	$
6.	Other Production	$	$	$
7.	Generator Step Up Related Depreciation (Note A)	$	$	$
8.	Production Related General & Intangible Plant (Note B)	$	$	$
9.	Total Production	$	$	$

Note: Lines 1 through 6 will be Depreciation Expense reported on P.336 of the FF1 excluding the amortization of acquisition adjustments. See Workpaper 6d.

Line 8 will be total General & Intangible Plant (from P.336 of the FF1, adjusted for amortization adjustments) times ratio of Production Related General Plant to total General Plant computed on P.7, L. 26, Col.(3)

Depreciation expense excludes amounts associated with ARO.

Note A: Line 7 , see P.3, L.5

Note B:

A	Production Related General & Intangible Plant		
B	General Plant	WP 6d	$
C	Intangible Plant	WP 6d	$
D	Total General & Intangible Plant	Ln. b + Ln. c	$

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E	Production Demand Labor Allocator	Pg. 7, Ln. 26	%
F	Production Demand Related General & Intangible	Ln. d x Ln. e	$
G	Production Energy Labor Allocator	Pg. 7, Ln. 26	%
H	Production Energy Related General & Intangible	Ln. d x Ln. g	$
I	Total Production Related General & Intangible Plant	Ln. f + Ln. h	$

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
RPODUCTION RELATED TAXES OTHER THAN INCOME TAXES
12 Months Ending 12/31/####

		SYSTEM		.	PRODUCTION
		REFERENCE	AMOUNT	%	AMOUNT
			(1)	(2)	(3)
	PRODUCTION RELATED TAXES OTHER THAN INCOME				
1	Labor Related	Note A	$	Note B	$
2	Property Related	Note A	$	Note C	$
3	Other	Note A	$	Note C	$
4	Production	Note A	$		$
5	Gross Receipts / Distribution Related	Note A	$	Note D	$
6	TOTAL TAXES OTHER THAN INCOME TAXES	Sum L.1 : L.5	$		$

Note A: See Workpaper 8c.

Note B: Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services shown on Worksheets WP-9a and WP-9b.

	Amount	%
(1) Total W & S (excl. A & G)	$	%
(2) Production W & S	$	%

Note C: Allocated on the basis of Gross Plant Investment from Schedule P. 6, Ln.7

Note D: Not allocated to wholesale

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
PRODUCTION-RELATED INCOME TAX
12 Months Ending 12/31/####

		Reference	Amount (1)	Demand (2)	Energy (3)
1.	Return on Rate Base	P.5, L.18	$	$	$
2.	Effective Income Tax Rate	P.19, L.2	%	%	%
3.	Income Tax Calculated	L.1 x L.2	$	$	$
4.	ITC Adjustment	P.19, L.13	$	$	$
5.	Income Tax	L.3 + L.4	$	$	$

Note A: Classification based on Production Plant classification of P.19, L.20 and L.21.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
COMPUTATION OF EFFECTIVE INCOME TAX RATE
12 Months Ending 12/31/####

		(1) Source	(2) Rates & Amounts
1.	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * P)} =		%
2.	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		%
3.	where WCLTD from P.11 L.1, Col (4) and WACC from P.11 L.,4, Col. (4) and FIT, SIT & P as shown below.		
4.	GRCF=1 / (1 - T)		#
5.	Federal Income Tax Rate	FIT	%
6.	State Income Tax Rate (Composite)	SIT	%
7.	Percent of FIT deductible for state purposes	P (Note A)	%
8.	Weighted Cost of Long Term Debt	WCLTD	%
9.	Weighted Average Cost of Capital	WACC	%
10.	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.c	$
11.	Gross Plant Allocation Factor	L.19	%
12.	Production Plant Related ITC Amortization	L.10 x L.11	$
13.	ITC Adjustment	L.12 x L.4	$
14.	Gross Plant Allocator		Total
15.	Gross Plant	P.6, L.4, Col.1	$
16.	Production Plant Gross	P.6, L.5, Col.2	$
17.	Demand Related Production Plant	P.6, L.5, Col.3	$
18.	Energy Related Production Plant	P.6, L.5, Col.4	$
19.	Production Plant Gross Plant Allocator	L.16 / L.15	%
20.	Production Plant - Demand Related	L.17 / L.16	%
21.	Production Plant - Energy Related	L.18 / L.16	%

Note A: Percent deductible for state purposes provided from Company's books and records.

APPALACHIAN POWER COMPANY
BLANK FORMULA RATE TEMPLATE
DEPRECIATION RATES
EFFECTIVE JUNE 1, 2015

Note: APCO will not change the depreciation or amortization rates shown on this page of the template absent a Section 205 or Section 206 filing.

STEAM PRODUCTION PLANT

Mountaineer Plant

311.0	Structures and Improvements	2.44%
312.0	Boiler Plant Equipment	2.75%
312.0	Boiler Plant Equipment – SCR Catalyst	6.99%
314.0	Turbogenerator Units	2.28%
315.0	Accessory Electric Equipment	1.80%
316.0	Misc. Power Plant Equipment	2.21%

Kanawha River Plant

311.0	Structures and Improvements	Retired
312.0	Boiler Plant Equipment	Retired
314.0	Turbogenerator Units	Retired
315.0	Accessory Electric Equipment	Retired
316.0	Misc. Power Plant Equipment	Retired

Amos Plant - Units 1 & 2

311.0	Structures and Improvements	2.03%
312.0	Boiler Plant Equipment	3.29%
312.0	Boiler Plant Equipment – SCR Catalyst	6.01%
314.0	Turbogenerator Units	3.32%
315.0	Accessory Electric Equipment	2.79%
316.0	Misc. Power Plant Equipment	3.10%

Amos Plant - Unit 3

311.0	Structures and Improvements	2.54%
312.0	Boiler Plant Equipment	3.56%
312.0	Boiler Plant Equipment – SCR Catalyst	7.63%
314.0	Turbogenerator Units	3.12%
315.0	Accessory Electric Equipment	2.17%
316.0	Misc. Power Plant Equipment	2.68%

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Sporn Plant

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Clinch River Plant

311.0 Structures and Improvements	3.86%
312.0 Boiler Plant Equipment	4.73%
314.0 Turbogenerator Units	3.68%
315.0 Accessory Power Equipment	4.37%
316.0 Misc Power Plant Equipment	7.11%

Glen Lyn Plant #5

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Glen Lyn Plant #6 and Common

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
314.0 Turbogenerator Units	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Putnam Coal Terminal

311.0 Structures and Improvements	Retired
312.0 Boiler Plant Equipment	Retired
315.0 Accessory Power Equipment	Retired
316.0 Misc Power Plant Equipment	Retired

Central Plant Maintenance	316.0 Misc Power Plant Equipment	2.51%
Central Machine Shop	316.0 Misc Power Plant Equipment	2.70%
Little Broad Run - Mountaineer	311.0 Structures and Improvements	3.34%
	312.0 Boiler Plant Equipment	3.24%
	315.0 Accessory Electric Equipment	3.41%

HYDRAULIC PRODUCTION PLANT

Claytor		
	331.0 Structures and Improvements	1.65%
	332.0 Reservoirs, Dams, Waterways	1.10%
	333.0 Waterwheels, Generators, Turbines	1.08%
	334.0 Accessory Plant Equipment	2.16%
	335.0 Misc Power Plant Equip	2.61%
	336.0 Roads, Railroads, Bridges	0.71%
Byllesby		
	331.0 Structures and Improvements	5.54%
	332.0 Reservoirs, Dams, Waterways	6.82%
	333.0 Waterwheels, Generators, Turbines	5.93%
	334.0 Accessory Plant Equipment	4.14%
	335.0 Misc Power Plant Equip	6.73%
Buck		
	331.0 Structures and Improvements	4.49%
	332.0 Reservoirs, Dams, Waterways	4.94%
	333.0 Waterwheels, Generators, Turbines	4.10%
	334.0 Accessory Plant Equipment	4.60%
	335.0 Misc Power Plant Equip	5.84%
	336.0 Roads, Railroads, Bridges	4.72%

Niagara

331.0	Structures and Improvements	2.58%
332.0	Reservoirs, Dams, Waterways	5.09%
333.0	Waterwheels, Generators, Turbines	4.00%
334.0	Accessory Plant Equipment	4.89%
335.0	Misc Power Plant Equip	4.83%

Reusens

331.0	Structures and Improvements	5.66%
332.0	Reservoirs, Dams, Waterways	5.77%
333.0	Waterwheels, Generators, Turbines	6.04%
334.0	Accessory Plant Equipment	5.04%
335.0	Misc Power Plant Equip	6.61%

Leesville

331.0	Structures and Improvements	1.04%
332.0	Reservoirs, Dams, Waterways	1.66%
333.0	Waterwheels, Generators, Turbines	1.33%
334.0	Accessory Plant Equipment	2.09%
335.0	Misc Power Plant Equip	2.12%
336.0	Roads, Railroads, Bridges	0.93%

London

331.0	Structures and Improvements	2.61%
332.0	Reservoirs, Dams, Waterways	2.40%
333.0	Waterwheels, Generators, Turbines	2.72%
334.0	Accessory Plant Equipment	2.59%
335.0	Misc Power Plant Equip	2.80%
336.0	Roads, Railroads, Bridges	1.68%

Marmet

331.0	Structures and Improvements	2.08%
332.0	Reservoirs, Dams, Waterways	2.73%
333.0	Waterwheels, Generators, Turbines	2.84%
334.0	Accessory Plant Equipment	2.62%
335.0	Misc Power Plant Equip	2.73%
336.0	Roads, Railroads, Bridges	1.71%

Winfield

331.0 Structures and Improvements	2.32%
332.0 Reservoirs, Dams, Waterways	2.14%
333.0 Waterwheels, Generators, Turbines	2.46%
334.0 Accessory Plant Equipment	2.40%
335.0 Misc Power Plant Equip	2.26%
336.0 Roads, Railroads, Bridges	2.44%

Smith Mountain

331.0 Structures and Improvements	1.31%
332.0 Reservoirs, Dams, Waterways	1.22%
333.0 Waterwheels, Generators, Turbines	2.24%
334.0 Accessory Plant Equipment	2.45%
335.0 Misc Power Plant Equip	2.67%
336.0 Roads, Railroads, Bridges	1.09%

<u>OTHER PRODUCTION PLANT</u>

Ceredo

341.0 Structures and Improvements	1.33%
344.0 Generators	1.44%
345.0 Accessory Electrical Equip.	1.35%
346.0 Misc Power Plant Equipment	2.84%

Dresden

341.0 Structures and Improvements	2.87%
342.0 Fuel Holders, Producers,and Acessories	2.88%
344.0 Generators	2.87%
345.0 Accessory Electrical Equip.	2.89%
346.0 Misc Power Plant Equipment	3.49%

GENERAL PLANT

390.0	Structures and Improvements	1.51%
391.0	Office Furniture and Fixtures	2.89%
392.0	Transportation Equipment	1.82%
393.0	Stores Equipment	1.76%
394.0	Tools, Shop & Garage Equip.	2.36%
395.0	Laboratory Equipment	2.65%
396.0	Power Operated Equipment	1.91%
397.0	Communications Equipment	4.06%
398.0	Misc Equipment	2.62%

INTANGIBLE PLANT

301.0	Organization	0.00%
302.0	Franchises & Consents	End of Life
303.0	Misc Intangible Plant	20.00%

Schedule 8.1 – Appendix 2C
Appalachian Power Company
Workpapers in Support of the Capacity Compensation Formula Rate

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 1 - Production System Peak Demand
For the Year Ending December 31, _ _ _ _

		(EDT)		
Month	Day	Hour	Demand (MW)	<u>Source</u>
July	#	#	#	CBR[1]
July	#	#	#	
July	#	#	#	
July	#	#	#	
June	#	#	#	
Average Peak			#	
Average Production System Peak Demand			#	

Company's average five CP demands at time of PJM system peak.

<u>Notes:</u>
[1]CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 2 - Production Revenue Credits
For the Year Ending December 31, _ _ _ _

	Production			Source 1
	Total	Demand	Energy	CBR[1]
	$	$	$	
Total	$	$	$	

Notes:

[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 3

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 4

Intentionally left blank - not applicable.

Appalachian Power Company

Capacity Cost of Service Formula Rate
Workpaper 5a - Materials and Supplies
Balances as of December 31, _ _ _ _

Period	Function	1540001 M&S Regular	1540004 M&S Exempt Material	1540006 Lime and Limestone	1540012 Urea Charge	1540013 Transportation Inventory	1540022 M&S Lime & Limestone Intrasit	1540023 M&S Urea	1540024 M&S Proj Spares	M&S Total	Source[1]
12/31/20##	Production	$	$	$	$	$	$	$	$	$	110.48.c
	Transmission	$	$	$	$	$	$	$	$	$	
	Distribution	$	$	$	$	$	$	$	$	$	
									Total	$	

Period		158 Allowances	Source[1]
12/31/20##	Production	$	110.52.c
	Transmission	$	
	Distribution	$	

M&S December 20##[2]		
Production	$	%
Transmission	$	%
Distribution	$	%
	$	%

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5b - Fuel Inventory
Balances as of December 31, _ _ _ _

Period	1510001 Fuel Stock Coal	1510002 Fuel Stock Oil	1510003 Fuel Stock Gas	1510004 Fuel Stock Coal Trans	1510019 Fuel Stock Prepays	1510020 Fuel Stock In Transit	Fuel Stock Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	110.45.c

Period	1520000 Fuel Stock Undistributed	Source [1]
12/1/20##	$	110.46.c

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 5c – Prepayments
For the Year Ending December 31, _ _ _ _

Period	1650001 Prepayments Insurance	1650004 Prepayments Rents	1650005 Prepayments Employee Benefits	1650006 Prepayments Other	1650009 Prepayments Carrying Cost	1650021/ 1650023 Prepayments Ins. & Lease	165000211* Prepayments Taxes	Prepayments Total	Source [1]
12/1/20##	$	$	$	$	$	$	$	$	111.57.c

Period	Exclude [2] Rate Base	Non Labor [2] Related	Labor [2] Related
12/1/20##	$	$	$

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] Data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.
1650001 - This account shall include amounts representing prepayments of insurance.
1650004 - This account shall include amounts representing prepayments of interest.
1650005 - This account shall include amounts representing prepayments of employee benefits.
1650006 - This account shall include amounts representing prepayments of other items not listed.
1650009 - This account is used for factoring the AEP-East electric accounts receivable.

1650021 - This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
1650023 - Track balance of prepaid lease expense for agreements that qualify as a lease under company policy and are not tracked in PowerPlant Lease Accounting system will use this account.

165000211 - This account shall include amounts representing prepayments of taxes.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6a - Plant in Service
Balances as of December 31, _ _ _ _

Line		Production					
		Total		ARO			Excluding ARO & AFUDC
	Month	Amount	Source [1]	Amount	Source [1]		
1	12/1/20##	$	205.46.g	$	205.15,24,34.44.g		$
2	Total						$
		Transmission					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
3	12/1/20##	$	207.58.g	$	207.57.g		$
4	Total						$
		Distribution					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
5	12/1/20##	$	207.75.g	$	207.74.g		$
6	Total						$
		General					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
7	12/1/20##	$	207.99.g	$	207.98.g		$
8	Total						$
		Intangible					
		Total		ARO			Excluding ARO
		Amount	Source [1]	Amount	Source [1]		
9	12/1/20##	$	205.5.g	$	CBR		$
10	Total						$
11	December 31, ______ Plant In Service (excluding ARO)						$

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6b - Accumulated Depreciation
Balance as of December 31, _ _ _ _

LINE	RESERVE ACCT (CBR)[1]	RESERVE AMOUNT	PRODUCTION	TRANSMISSION	DISTRIBUTION	GENERAL
1	1080005	$	$	$	$	$
2	1080001 ARO	$	$	$	$	$
3	1080001/1080011	$	$	$	$	$
4	1110001	$	$	$	$	$
5	10800013	$	$	$	$	$
6	TOTAL RESERVE (FF1 200.22.(b)[3].	$	$	$	$	$
7	(Ln 6 – Ln 2) APCo Exc. ARO [1,2]	$	$	$	$	$
8	(Ln 6 – Ln 7) FF1 pg. 219.29.(b)[3]	$	$	$	$	$
9	(Ln 4) FF1 pg. 200.18.(b)[3]	$				
10	(Ln 8 + Ln 9) Total Check FF1 pg. 200.(b).	$				

Notes:
[1] CBR indicates that data comparable to that reported in the FERC From 1 is from the Company's Books and Records.

[2] Note: Excludes reserve on Asset Retirement Obligations, to reflect their removal from gross plant.

[3] References to data from FERC Form 1 are indicated as page#, line#, col.# for the total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6c - General Plant and Intangible Plant
Balances as of December 31, _ _ _ _

Description	Account	12/31/20##
INTANGIBLE PLANT (FF1 205.2-5.g)		
Organization	301	$
Franchises and Consents	302	$
Miscellaneous Intangible Plant	303	$
TOTAL INTANGIBLE PLANT		$
GENERAL PLANT (FF1 207.86-97.g)		
Land	389	$
Structures	390	$
Office Equipment	391	$
Transportation	392	$
Stores Equipment	393	$
Tools, Shop, Garage, Etc.	394	$
Laboratory Equipment	395	$
Power Operated Equipment	396	$
Communications Equipment	397	$
Miscellaneous Equipment	398	$
Fuel Exploration	399	$
TOTAL GENERAL PLANT		$
General Plant (FF1 207.86-97 g)		
Total General and Intangible Exc. ARO		$
Total General and Intangible	205.5.g, 207.99.g	$

Note: Total includes Intangible Plant.
References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 6d - Depreciation Expense
For the Year Ending December 31, _ _ _ _

Description	Amount	Source
Steam Production	$	FF1, 336, 2, b & d
Hydraulic Production		
Conventional	$	FF1, 336, 4, b
Pumped Storage	$	FF1, 336, 5, b
Other Production Plant	$	FF1, 336, 6 b
Transmission	$	FF1, 336, 7, b
Distribution	$	FF1, 336, 8, b
General	$	FF1, 336, 10, b & d
Intangible Plant	$	FF1, 336, 1,d
Sub-Total	$	
ARO Dep Exp	$	FF1, 336, 12, c
Total Depr Expense	$	FF1, 336, 12, f

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 7

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 281: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 281	$	$	$		
	FF1, pg.273, Ln.8					
2	ACCOUNT 282:					
3	*Listing of Individual Tax Differences*					
4	**TOTAL ACOUNT 282**	$	$	$	$	$
5	***FF1, pg. 275, Ln. 5***					
6	**Labor Related**			$	$	$
7	**Energy Related**			$	$	$
8	**ARO**			$	$	$
9	**Demand Related**			$	$	$
10	**Excluded**			$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8a - Specified Deferred Credits
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN L
		PER BOOKS	NON-APPLICABLE/NON-UTILITY	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-##	BALANCE AS OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
11	ACCOUNT 283:					
12	Listing of Individual Tax Differences					
13	TOTAL ACCOUNT 283	$	$	$	$	$
14						
15	FF1, pg. 277, Ln. 9					
16	Labor Related			$	$	$
17	Energy Related			$	$	$
18	ARO			$	$	$
19	Demand Related			$	$	$
20	Excluded			$		
21	JURISDICTIONAL AMOUNTS FUNCTION					

	ALIZED TOTAL COMPANY AMOUNTS FUNCTION				
22	ALIZED REFUNCTI ONALIZED BASED ON JURISDICTI ONAL				
23	PLANT NOTE: POST 1970 ACCUMUL ATED				
24	DEFERRED INV TAX CRED. (JDITC) IN				
25	A/C 255 SEC ALLOC - ITC - 46F1				
26	- 10%	$	$	$	$
	HYDRO CREDIT -				
27	ITC - 46F1	$	$	$	$
28					
	TOTAL ACCOUNT				
29	255	$	$	$	$
	ITC Balance Included in				
30	Ratebase	$	$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8ai - ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190
For the Year Ending December 31, _ _ _ _

	COLUMN A	COLUMN B	COLUMN D	COLUMN J	COLUMN K	COLUMN O
		PER BOOKS BALANCE AS	NON-APPLICABLE/NON-UTILITY BALANCE AS	FUNCTIONALIZATION 12/31/##		
	ACCUMULATED DEFERRED FIT ITEMS	OF 12-31-##	OF 12-31-##	GENERATION	TRANSMISSION	DISTRIBUTION
	ACCOUNT 190: *Listing of Individual Tax Differences*					
1	TOTAL ACCOUNT 190 FF 1, p. 234, L. 8 Col. (c)	$	$	$	$	$
	Energy Related			$	$	$
	ARO			$	$	$
	Labor Related			$	$	$
	Demand Related			$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8b - Effective Income Tax Rate
For the Year Ending December 31, _ _ _ _'

Effective Income Tax Rate

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * P)} =	%	
EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =	%	
where WCLTD and WACC from Appendix 2 p. 11, Col (4).		
and FIT, SIT & P are as shown below.		
GRCF=1 / (1 - T)		#

Amortized Investment Tax Credit (enter negative)	FF1 P.114, Ln.19, Col.c	$
Federal Income Tax Rate	FIT	%
State Income Tax Rate (Composite).	SIT	%
Percent of FIT deductible for state purposes	P (Note 3)	%
Weighted Cost of Long Term Debt	WCLTD	%
Weighted Average Cost of Capital	WACC	%

Development of Composite State Income Tax Rates for 2011 (Note 1)

Tennessee Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Michigan Business Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Virginia Net Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
West Virginia Net Income	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Illinois Corporation Income Tax	%	
Apportionment Factor - Note 2	%	
Effective State Income Tax Rate		%
Total Effective State Income Tax Rate	%	

Note 1: Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction
.
Note 2: From Company Books and Records.
Note 3: Percent deductible for state purposes provided from Company’s books and records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _[1/]

Payroll Related Other Taxes	$	Payroll
Property Related Other Taxes	$	Property
Direct Production Related	$	Production
Direct Distribution Related	$	Distribution
Other (Misc Taxes Allocated on Gross Plant)	$	Other
Not Allocated ((Gross Receipts, Commission Assessments)	$	NA
	$	

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type	FERC FORM 1 Tie-Back	FERC FORM 1 Reference	Basis
1	**Revenue Taxes**			
2	Gross Receipts Tax			
		$	P.263.1 ln 7 (i)	N/A
		$	P.263.1 ln 34 (i)	N/A
		$	P.263.1 ln 35 (i)	N/A
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - West Virginia			
		$	P.263 ln 34 (i)	Property
		$	P.263 ln 35 (i)	Property
		$	P.263 ln 37 (i)	Property
		$	P.263 ln 38 (i)	Property
		$	P.263 ln 39 (i)	Property
		$	P.263 ln 40 (i)	Property
		$	P.263.1 ln 2 (i)	Property
		$	P.263.1 ln 3 (i)	Property
5	Real and Personal Property – Virginia			
		$	P.263.2 ln 19 (i)	Property
		$	P.263.2 ln 20 (i)	Property
		$	P.263.2 ln 21 (i)	Property
		$	P.263.2 ln 23 (i)	Property
		$	P.263.2 ln 24 (i)	Property
		$	P.263.2 ln 25 (i)	Property
		$	P.263.2 ln 26 (i)	Property
		$	P.263.2 ln 27 (i)	Property
6	Real and Personal Property – Tennessee			
		$	P.263.3 ln 7 (i)	Property
		$	P.263.3 ln 8 (i)	Property
7	Real and Personal Property - Other Jurisdictions			
		$	P.263.1 ln 37 (i)	Property
		$	P.263.4 ln 5 (i)	Property

1/ This version of Workpaper 8c ("Taxes Other Than Income Taxes") includes FERC Form 1 line and column references from APCo's FERC Form 1 for calendar year 2011. These references are illustrative for future years, as Taxes Other Than Income Taxes may be reported on different lines and columns in future APCo FERC Form 1 submissions. In each future FERC Form 1, APCo will report on Page 263 the Taxes Other Than Income Taxes that were paid in the applicable calendar year on a basis similar to the manner in which such Taxes Other Than Income Taxes were reported on APCo's FERC Form 1 for calendar year 2011.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

Line No.	(A) Annual Tax Expenses by Type	(B) FERC FORM 1 Tie-Back	(C) FERC FORM 1 Reference	(D) Basis
8	**Payroll Taxes**			
9	Federal Insurance Contribution (FICA)	$	P.263 ln 6 (i)	Payroll
10	Federal Unemployment Tax	$	P.263 ln 9 (i)	Payroll
11	State Unemployment Insurance	$	P.263.1 ln 22 (i)	Payroll
		$	P.263.2 ln 34 (i)	Payroll
		$	P.263.3 ln 20 (i)	Payroll
12	**Production Taxes**			
13	State Severance Taxes			
		$		
14	**Miscellaneous Taxes**			
15	State Business & Occupation Tax			
		$	P.263 ln 21 (i)	Production
		$	P.263 ln 22 (i)	Production
		$	P.263 ln 23 (i)	Production
16	State Public Service Commission Fees			
		$	P.263 ln 26 (i)	Other
		$	P.263 ln 27 (i)	Other
17	State Franchise Taxes			
		$	P.263.1 ln 25 (i)	Other
		$	P.263.1 ln 28 (i)	Other
		$	P.263.1 ln 29 (i)	Other
		$	P.263.2 ln 8 (i)	Other
		$	P.263.2 ln 9 (i)	Other
		$	P.263.3 ln 4 (i)	Other
		$	P.263.3 ln 33 (i)	Other
18	State Lic/Registration Fee			
		$	P.263.2 ln 11 (i)	Other
		$	P.263.3 ln 12 (i)	Other
		$	P.263.1 ln 13 (i)	Other
19	Misc. State and Local Tax			
		$	P.263.1 ln 11 (i)	Other
		$	P.263.4 ln 23 (i)	Other
		$	P.263.3 ln 24 (i)	Other
20	Sales & Use			
		$	P.263 ln 30 (i)	Other
		$	P.263 ln 31(i)	Other
		$	P.263 ln 32(i)	Other
		$	P.263.2 ln 14 (i)	Other
		$	P.263.2 ln 15 (i)	Other

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 8c - Taxes Other Than Income Taxes
For the Year Ending December 31, _ _ _ _

	(A)	(B)	(C)	(D)
Line No.	**Annual Tax Expenses by Type**	**FERC FORM 1 Tie-Back**	**FERC FORM 1 Reference**	Basis
21	Federal Excise Tax	$	P.263 ln 14 (i)	Production
22	Michigan Single Business Tax	$	P.263.3 ln 12 (i)	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	$		

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9a - Wages and Salaries
For the Year Ending December 31, _ _ _ _

	APCo [1]	AEPSC [2]	Total
Production:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Transmission:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Distribution:			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Customer Accounts	$	$	$
Customer Service and Informational	$	$	$
Sales	$	$	$
Total Wages and Salaries Excluding A & G	$	$	$
Administrative and General			
Operation	$	$	$
Maintenance	$	$	$
Total	$	$	$
Total O & M Payroll	$	$	$

[1] APCo Wages and Salaries from FERC Form Pg. 354.
[2] From Company Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 9b - Production Payroll Demand/Energy Allocation
For the Year Ended December 31, 20XX

	Account	Demand	Energy	Total	Source CBR[1]
500	Operation Supv & Engineering	$	$		
501	Fuel		$	$	
502	Steam Expenses	$		$	
505	Electric Expenses	$		$	
506	Misc. Steam Power Expense	$		$	
510	Maintenance Supv & Engineering		$	$	
511	Maintenance of Structures	$		$	
512	Maintenance of Boiler Plant		$	$	
513	Maintenance of Electric Plant		$	$	
514	Maintenance of Misc Plant	$		$	
517	Operation Supv & Engineering	$		$	
519	Coolants and Water	$		$	
520	Steam Expenses	$		$	
523	Electric Expenses	$		$	
524	Misc. Nuclear Power Expense	$		$	
528	Maintenance Supv & Engineering		$	$	
529	Maintenance of Structures	$		$	
530	Maintenance of Reactor Plant		$	$	
531	Maintenance of Electric Plant		$	$	
532	Maintenance of Misc. Nuclear Plant		$	$	
535	Operation Supv & Engineering	$		$	
536	Water for Power	$		$	
537	Hydraulic Expenses	$		$	
538	Electric Expenses	$		$	
539	Miscellaneous Hydraulic Power	$		$	
541	Maintenance Supv & Engineering	$		$	
542	Maintenance of Structures	$		$	
543	Maint. of Reservoirs, Dams and Waterways	$		$	
544	Maintenance of Electric Plant		$	$	
545	Maintenance of Misc. Hydraulic Plant	$		$	
546	Operation Supv & Engineering	$		$	
547	Fuel		$	$	
548	Generation Expenses	$		$	
549	Misc. Power Generation Exp	$		$	
553	Maintenance of Generating & Electric Plant	$		$	
554	Maintenance of Misc. Other Power Gen. Plant	$		$	
555	Purchased Power	$	$	$	
556	System Control	$		$	
557	Other Expense	$		$	
	Total Allocated Labor Expense	$	$	$	
		%	%	%	

[1] CBR indicates that data comparable to that reported in the FERC Form 1's from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

	Production		
	Expense Account		Source
500	Operation Supv & Engineering	$	320.6.(b)
501	Fuel	$	320.7.(b)
502	Steam Expenses	$	320.8.(b)
505	Electric Expenses	$	320.9.(b)
506	Misc. Steam Power Expense	$	320.10.(b)
507	Rents	$	320.11.(b)
509	Allowances	$	320.12.(b)
517	Operation Supv & Engineering	$	320.24.(b)
518	Fuel	$	320.26.(b)
519	Coolants and Water	$	320.27.(b)
520	Steam Expenses	$	320.30.(b)
523	Electric Expenses	$	320.31.(b)
524	Misc. Nuclear Power Expense	$	320.32.(b)
535	Operation Supv & Engineering	$	320.44.(b)
536	Water for Power	$	320.45.(b)
537	Hydraulic Expenses	$	320.46.(b)
538	Electric Expenses	$	320.47.(b)
539	Miscellaneous Hydraulic Power	$	320.48.(b)
540	Rents	$	320.40.(b)
546	Operation Supv & Engineering	$	321.62.(b)
547	Fuel	$	321.63.(b)
548	Generation Expenses	$	321.64.(b)
549	Misc. Power Generation Expense	$	321.65.(b)
	Total Operation	$	320.23.(b)
510	Maintenance Supv & Engineering	$	320.15.(b)
511	Maintenance of Structures	$	320.16.(b)
512	Maintenance of Boiler Plant	$	320.17.(b)
513	Maintenance of Electric Plant	$	320.18.(b)
514	Maintenance of Misc Plant	$	320.19.(b)
528	Maintenance Supv & Engineering	$	320.35.(b)
529	Maintenance of Structures	$	320.36.(b)
530	Maintenance of Reactor Plant	$	320.37.(b)
531	Maintenance of Electric Plant	$	320.38.(b)
532	Maintenance of Misc. Nuclear Plant	$	320.39.(b)
541	Maintenance Supv & Engineering	$	320.53.(b)
542	Maintenance of Structures	$	320.54.(b)
543	Maintenance of Reservoirs, Dams and Waterways	$	320.55.(b)
544	Maintenance of Electric Plant	$	320.56.(b)
545	Maintenance of Miscellaneous Hydraulic Plant	$	320.57.(b)
551	Maintenance Supv & Engineering	$	321.69.(b)
553	Maintenance of Generating & Electric Plant	$	321.71.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

554	Maintenance of Misc. Other Power Gen. Plant	$	321.72.(b)
	Total Maintenance	$	
555	Purchased Power	$	321.76.(b)
556	System Control	$	321.77.(b)
557	Other Expense	$	321.78.(b)
	Total Other	$	
	Total Production	$	
560	Operation Supv & Engineering	$	321.83.(b)
561.1	Load Dispatch-Reliability	$	321.85.(b)
561.2	Load Dispatch-Monitor and Operate	$	321.86.(b)
561.3	Load Dispatch-Transmission Service	$	321.87.(b)
561.4	Scheduling, System Control	$	321.88.(b)
561.5	Reliability, Planning and Standards Dev.	$	321.89.(b)
561.6	Transmission Service Studies	$	321.90.(b)
561.7	Generation Interconnection Studies	$	321.91.(b)
561.8	Reliability, Planning and Standards Dev.	$	321.92.(b)
562	Station Expense	$	321.93.(b)
563	Overhead Line Expense	$	321.94.(b)
564	Underground Line Expense	$	321.95.(b)
565	Trans of Electricity by Others	$	321.96.(b)
566	Misc Transmission Expense	$	321.97.(b)
567	Rents	$	321.98.(b)
	Total Operation	$	
568	Maintenance Supv & Engineering	$	321.101.(b)
569	Maintenance of Structures	$	321.102.(b)
569.1	Maintenance of Computer Hardware	$	321.103.(b)
569.2	Maintenance of Computer Software	$	321.104.(b)
569.3	Maintenance of Communication Equip	$	321.105.(b)
570	Maintenance of Station Equip	$	321.107.(b)
571	Maintenance of OH Lines	$	321.108.(b)
572	Maintenance of UG Lines	$	321.109.(b)
573	Maintenance of Misc Trans	$	321.110.(b)
	Total Maintenance	$	
	Total Transmission	$	
575.7	Market Facilitation, Monitoring and Compliance	$	322.121.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

580	Operation Supv & Engineering	$	322.134.(b)
581	Load Dispatching	$	322.135.(b)
582	Station Expense	$	322.136.(b)
583	Overhead Line Expense	$	322.137.(b)
584	Underground Line Expense	$	322.138.(b)
585	Street Lighting	$	322.139.(b)
586	Meter Expenses	$	322.140.(b)
587	Customer Installations	$	322.141.(b)
588	Misc Distribution Expense	$	322.142.(b)
589	Rents	$	322.143.(b)
	Total Operation	$	322.144.(b)
		$	
590	Maintenance Supv & Engineering	$	322.146.(b)
591	Maintenance of Structures	$	322.147.(b)
592	Maintenance of Station Equip	$	322.148.(b)
593	Maintenance of OH Lines	$	322.149.(b)
594	Maintenance of UG Lines	$	322.150.(b)
595	Maintenance of Line Trsfrs	$	322.151.(b)
596	Maintenance of Street Lights	$	322.152.(b)
597	Maintenance of Meters	$	322.153.(b)
598	Maintenance of Misc Dist Plant	$	322.154.(b)
	Total Maintenance	$	322.155.(b)
	Total Distribution	$	
901	Supervision	$	322.159.(b)
902	Meter Reading Expenses	$	322.160.(b)
903	Customer Records/Collection	$	322.161.(b)
904	Uncollectible Accounts	$	322.162.(b)
905	Misc Customer Accts Exp	$	322.163.(b)
	Total Customer Accounts	$	322.164.(b)
907	Supervision	$	323.167.(b)
908	Customer Assistance	$	322.168.(b)
909	Info & Instructional Adv	$	322.169.(b)
910	Misc Cust Service & Info Expense	$	322.170.(b)
	Total Customer Service	$	
911	Supervision	$	323.174.(b)
912	Selling Expenses	$	323.175.(b)
913	Advertising Expenses	$	323.176.(b)
916	Misc Sales Expense	$	323.177.(b)
	Total Sales Expense	$	

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 10a - O & M Expense Summary by Account
For the Year Ended December 31, _ _ _ _

920	A & G Salaries	$	323.181.(b)
921	Office Supplies & Exp	$	323.182.(b)
922	Adm Exp Trsfr – Credit	$	323.183.(b)
923	Outside Services	$	323.184.(b)
924	Property Insurance	$	323.185.(b)
925	Injuries and Damages	$	323.186.(b)
926	Employee Benefits	$	323.187.(b)
926a	Less: Actual Employee Benefits (Note A)	$	
926b	Allowed Employee Benefits (Note B)	$6,222,780	
926	Employee Benefits	$	
927	Franchise Requirements	$	323.188(b)
928	Regulatory Commission Exp	$	323.189.(b)
929	Duplicate Charges – Credit	$	323.190.(b)
930.1	General Advertising Expense	$	323.191.(b)
930.2	Misc General Expense	$	323.192.(b)
930.2	Company Dues and Memberships	$	
931	Rents	$	323.193.(b)
	Total Operation	$	323.194.(b)
935	Maintenance of Gen Plant	$	323.196.(b)
	Total Maintenance	$	
	Total Administrative & General	$	323.197.(b)
	Total O & M Expenses	$	323.198.(b)
	Total Elec O & M Exp. - FERC Form1 pg. 323, L. 198(b)	$	
	Difference		

Actual Expense - Removed from Cost of Service		
Note A:	Acct 926 (0039) PBOP Gross Cost	$
	Acct 926 (0057) PBOP Medicare Part Subsidy	$
	PBOP Amounts in Annual Informational Filing	$

Allowable Expense		
Note B:	Acct 926 (0039) PBOP Gross Cost	$ 10,806,289
	Acct 926 (0057) PBOP Medicare Part Subsidy	$(4,583,509)
	PBOP Amounts Recovery Allowance	$6,222,780

Note B: Changing PBOP included in the formula rate will require, as applicable, a FPA Section 205 or Section 206 filing.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 11 – Regulatory Commission Expense
For the Year Ended December 31, 20XX[1/]

Retail		
Misc. Exp.	FF1 pg 351. Ln 34. Col (h).	$
Virginia Base Case	FF1 pg 351. Ln. 35, Col (h).	$
Virginia E&R Filing	FF1 pg 351. Ln. 37, Col (h).	$
Virginia ERAC	FF1 pg 351. Ln. 39, Col (h).	$
Virginia GRAC	FF1 pg 351. Ln. 41, Col (h).	$
Virginia RPS-RAC	FF1 pg 351. Ln. 43, Col (h).	$
West Virginia Base Case	FF1 pg 351. Ln. 45, Col (h).	$
Total Retail		$
Wholesale – FERC[2]		
Smith Mountain	FF1 pg 351. Ln. 3, Col (h).	$
Leesville Hydro Project	FF1 pg 351. Ln. 7, Col (h).	$
Claytor Hydro Project	FF1 pg 351. Ln. 11, Col (h).	$
Byllesby Buck Hydro Project	FF1 pg 351. Ln. 15, Col (h).	$
Marmet and London Hydro Project	FF1 pg 351. Ln. 19, Col (h).	$
Winfield Hydro Project	FF1 pg 351. Ln. 23, Col (h).	$
Ruesens Hydro Project	FF1 pg 351. Ln. 27, Col (h).	$
Niagara Hydro Project	FF1 pg 351. Ln. 31, Col (h).	$
Total Wholesale		$
Total FF1, pg. 351, Ln. 46, Col (h)		$

1) This version of Workpaper 11 (“Regulatory Commission Expense”) includes FERC Form 1 line and column references from APCo’s FERC Form 1 for calendar year 2011. These references are illustrative for future years, as Regulatory Commission Expenses may be reported on different lines and columns in future APCo FERC Form 1 submissions. In each future FERC Form 1, APCo will report on Page 351 the Regulatory Commission Expenses that were incurred in the applicable calendar year on a basis similar to the manner in which such Regulatory Commission Expenses were reported on APCo’s FERC Form 1 for calendar year 2011

2) Assessment for cost of administration of Federal Water Power Act

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, _ _ _ _

Line	Month	Total Capital	Source(s)	Preferred Stock Issued	Preferred Stock Premium (Discount)	Preferred Stock G(L) on Reacq'd	Preferred Stock Source(s)*	Unapprop Sub Earnings	Source	Acc Oth Comp Income	Source	Common Equity Balance
		a		b	C	d		E		f		g=a-b-c-d-e-f
1	12/1/20##	$	112.16.c	$	$	$	112.3.c,6.c., 7.c.	$	112.12. c.	$	112.15. c.	$

NOTE: * Includes preferred portions of capital stock (common and preferred) accounts according to Company Books and Records below.

Line	Account	Description		12/1/20##
2	2010001	Common Stock Issued		$
		Source [1]		*112.2.c*
3	2040002	PS Not Subj to Mandatory Redem		$
		Source [1]		*112.3.c*
4	2070000	Prem on Capital Stk		$
		Source [1]		*112.6.c*
5	2080000	Donations Recvd from Stckhldrs	CBR[2]	$
6	2100000	Gain Rsle/Cancl Req Cap Stock	CBR[2]	$
7	2110000	Miscellaneous Paid-In Capital	CBR[2]	$
8				$
		Source [1]		*112.7.c*
9	2151000	Appropriations of Retained Earnings	CBR[2]	$
10	2160001	Unapprp Retnd Erngs-Unrstrictd	CBR[2]	$
11	4330000	Transferred from Income	CBR[2]	$
12	4370000	Div Decl-PS Not Sub to Man Red	CBR[2]	$
13	4380001	Dividends Declared	CBR[2]	$
14	4390000	Adj to Retained Earnings	CBR[2]	$
		Retained Earnings		$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12a - Common Stock
For the Year Ending December 31, _ _ _ _

	Account	Description		12/1/20##
		Source [1]		*112.11.c*
15	2161001	Unap Undist Consol Sub Erng	CBR[2]	$
16	2161002	Unap Undist Nonconsol Sub Erng	CBR[2]	-
17	4181001 & 002	Equity in Earnings	CBR[2]	-
18		Unapprop Sub Earnings	CBR[2]	$
		Source [1]		*112.12.c*
19	2190002	OCI-Min Pen Liab FAS 158-Affil	CBR[2]	$
20	2190004	OCI-Min Pen Liab FAS 158-SERP	CBR[2]	$
21	2190006	OCI-Min Pen Liab FAS 158-Qual	CBR[2]	$
22	2190007	OCI-Min Pen Liab FAS 158-OPEB	CBR[2]	$
23	2190010	OCI-for Commodity Hedges	CBR[2]	$
24	2190015	Accum OCI-Hdg-CF-Int Rate	CBR[2]	$
25	2190016	Accum OCI-Hdg-CF-For Exchg	CBR[2]	-
26		Acc Oth Comp Inc		$
		Source [1]		*112.15.c*
27		Total Capital	CBR[2]	$
28		Common Equity Balance	CBR[2]	$

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
[2] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 12b - Preferred Stock
For the Year Ending December 31, _ _ _ _

	Preferred Stock		Premium on Preferred						Total Outstanding	Preferred
	A		B						C=A+B	
Month	Acct 204	Source 1	Acct 207	Source 1						Dividends
12/1/20##	$	112.3.c	$	112.6.c					$	$
Total	$		$						$	$

Cost of Preferred Stock = Pfd Dividends/Average Pfd Outstanding Balance = %

NOTES:
(1) All data is from the monthly Balance Sheet of the Company's Books and Records (CBR).
(2) Accounts 207-213 are capital stock accounts containing both common and preferred capital. Preferred portions of these accounts are from the CBR.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13 - Outstanding Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Period	Advances from Associated Co	FF1 Reference	Bonds	FF1 Reference	(Reacquired Bonds)	FF1 Reference	Installment Purchase Contracts	FF1 Reference	Senior Unsecured Notes	FF1 Reference	Debntr Trust Pref Secrty Insts	FF1 Reference	Total Debt Outstanding	Reference
		2230000		2210000		2220001		2240002		2240006		2240046			
		A		b		C		d		e		F		g=a+b+c +d+e+f	
1	12/1/20##	$	112.20.c.	$	112.18.c.	$	112.19.c.	$	257, col. (h)	$	257, col. (h)	$	257, col. (h)	$	FF1, 112,20,c & 112,21,c
2	12/1/20##	$		$		$		$		$		$		$	

Appalachian Power Company
Workpaper 13 Interest & Amortization on Long-Term Debt
For the Year Ending December 31, _ _ _ _

Line	Description		Acct		Amount
1	Interest	IPC	4270002		$
2	Interest	Unsecured	4270006		$
3	Interest	TPS	4270040		$
4			(FF1, P.117,L.62)		$
5	Amort Debt Disc/ Exp		Acct 428 (FF1, P.117, L.63)		$
6	Amort Loss Reacq		Acct 428.1 (FF1, P.117, L.64)		$
7	Interest*	Assoc LT	4300001 (FF1, P.117, L.67)		$
8	Amort Debt Premium	Amort Gain Reacq	Acct 429 (FF1, P.117, L.65)		$
9			Acct 429.1 (FF1, P.117, L.66)		$
10	Cost of Long Term Debt				$
11	Reconcilation to FF1, 257, 33,				
12	Interest on LT Debt		Line 4		$
13	Interest on Assoc LT Debt		Line 7		$
14	Total (FF1, 257, 33, i)			$	
15	Amortization of Hedge Gain / Loss included in Acct 4270006 (subject to limit on Workpaper 13a)			$	

*Per Company Books and Records Interest associated with LTD.

Reconciliation Account 430

4300001 Interest Expense Long Term Debt $

4300003 Interest Expense Short Term Debt	$
FF1, pg. 117, Ln. 67	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 13a - Recoverable Hedge Gains/Losses
For the Year Ended December 31, _ _ _ _

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge Gain or Loss for _ _ _ _	Less Excludable Amounts (See NOTE on Line For the Year Ended December 31, _ _ _ _)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
1	Listing of Debt Issues with Hedging	$	$	$	$	11/1/20##	11/1/20##
2		$	$	$	$	12/1/20##	12/1/20##
3		$	$	$	$	11/1/20##	11/1/20##
4		$	$	$	$	12/1/20##	12/1/20##
5		$	$	$	$	11/1/20##	11/1/20##
6		$	$	$	$	12/1/20##	12/1/20##
7		$	$	$	$	11/1/20##	11/1/20##
8		$	$	$	$	12/1/20##	12/1/20##
9		$	$	$	$	11/1/20##	11/1/20##
10		$	$	$	$	12/1/20##	12/1/20##
11	Total Hedge Amortization	$	$	$			

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 - Non-Fuel Power Production O&M Expenses
For the Year Ending December 31, _ _ _ _

Account		December	Less Carbon Capture Expense	Total	Source[1/]
500	Demand	$		$	320.4.(b)
502	Demand	$		$	320.6.(b)
503	Energy	$		$	320.7.(b)
504 - Cr.	Energy	$		$	320.8.(b)
505	Demand	$		$	320.9.(b)
506	Demand	$	$	$	320.10.(b)
507	Demand	$		$	320.11.(b)
509	Energy	$		$	320.12.(b)
510	Energy	$		$	320.15.(b)
511	Demand	$		$	320.16.(b)
512	Energy	$		$	320.17.(b)
513	Energy	$		$	320.18.(b)
514	Demand	$		$	320.19.(b)
517	Demand	$		$	320.24.(b)
519	Demand	$		$	320.26.(b)
520	Demand	$		$	320.27.(b)
521	Demand	$		$	320.28.(b)
522 - Cr.	Demand	$		$	320.29.(b)
523	Demand	$		$	320.30.(b)
524	Demand	$		$	320.31.(b)
525	Demand	$		$	321.32.(b)
528	Energy	$		$	321.35.(b)
529	Demand	$		$	321.36.(b)
530	Energy	$		$	321.37.(b)
531	Energy	$		$	320.38.(b)
532	Energy	$		$	320.39.(b)
535	Demand	$		$	320.44.(b)
536	Demand	$		$	320.45.(b)
537	Demand	$		$	320.46.(b)
538	Demand	$		$	320.47.(b)
539	Demand	$		$	320.48.(b)
540	Demand	$		$	320.50.(b)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 14 – Non-Fuel Power Production O&M Expense
For Year Ended December 31, 20XX

Account		December	Less Carbon Capture Expense	Total	Source [1/]
541	Demand	$		$	320.53.(b
542	Demand	$		$	320.54.(b
543	Demand	$		$	320.55.(b
544	Energy	$		$	320.56.(b
545	Demand	$		$	320.57.(b
546	Demand	$		$	320.62.(b
548	Demand	$		$	320.64(b
549	Demand	$		$	320.63.(b
550	Demand	$		$	320.64.(b
551	Demand	$		$	320.69.(b
552	Demand	$		$	320.70.(b
553	Demand	$		$	320.71.(b
554	Demand	$		$	320.72.(b
Total		$	$	$	
Demand		$	$	$	
Energy		$	$	$	
Total		$	$	$	
Demand	%			%	
Energy	%			%	
Total	%			%	

Notes:
[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances pages 320-323, ,b.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15a

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15b

Intentionally left blank - not applicable.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15c - Purchased Power
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Energy ($) [1]	Other Charges [2]	Total Purchased Power Expense
12/1/20##	$	$	$	$
Total	$	$	$	$
	327, ,,j	327, , k	327,,l	327,,m

Notes:

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.

[2] The deferred portion of APCo's capacity equalization payments related to environmental compliance investments FF 1, pg. 327, column (l)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 15d - Off-System Sales
For the Year Ending December 31, _ _ _ _

Month	Demand ($) [1]	Other Charges ($) [1]	Energy ($) [1]	Total
12/1/20##	$	$	$	$

Month	($) Margins [2]
12/1/20##	$

[1] References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
FF1, 311, h, j, I (Non-RQ)

[2]Margins provided by Accounting (represents 75% of system sales margins)

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 16 - GSU Plant and Accumulated Depreciation Balance
For the Year Ending December 31, ______

Company	major_location	asset_location	gl_account	state	utility_account	month	book_cost	allocated_reserve	net_book_value
Listing of Individual GSU Assets							$	$	$
Appalachian Power – Gen Total							$	$	$

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 17 – Balance of Transmission Investment
Balance as of December _ _ _ _

fr_desc	Fpa	fc_sortid	Description	Beginning_balance	additions	retirements	transfers	Adjustments	ending_balance	start_month	end_month
None	353 - Station Equipment	6	Transmission Plant - Electric	$	$	$	$	$	$	1/1/20##	12/1/20##

Notes:
References to data from FERC Form 1 page(s) 206,207, Ln. 50

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 18 - Fuel Expense
For the Year Ending December 31, _ _ _ _

		Source[1]
Fuel		
Fuel - Account 501	$	320, 5, b
Fuel - Account 518	$	320, 25, b
Fuel - Account 547	$	321, 63, b
Total Fuel	$	
Other		
Fuel Handling	$	CBR[2]
Sale of Fly Ash (Revenue & Expense)	$	CBR[2]

Notes:
1) References to data from FERC Form 1 are indicated as page#, line#, col.# for the ending total balances.
2) CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

Appalachian Power Company
Capacity Cost of Service Formula Rate
Workpaper 19 - Plant Held for Future Use
For the Year Ending December 31, _ _ _ _

	End of Year		
	Total	Demand [1]	Energy
Production	$	$	$
Transmission	$		
Distribution	$		
General	$		
Total	$	$	$
	FF1, 214, d		

Notes:
[1] CBR indicates that data comparable to that reported in the FERC Form 1 is from the Company's Books and Records.

SCHEDULE 9

PROCEDURES FOR
ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of the Interconnection and maintained in the PJM Manuals.

B. The rules and procedures shall recognize the difference in the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow and/or reservoir storage for hydro units, energy storage capability for Energy Storage Resources, energy source variability and intermittency, mechanical limitations, and system operating policies. For this purpose, the basis for determining and demonstrating the capability of a particular generating unit shall be described in RAA, Schedule 9.

C. For Delivery Years through the 2024/2025 Delivery Year

For Unlimited Resources, the capability of the generating unit is based on the level of output that the unit can provide under the site conditions expected to exist at the time of PJM system peak load where such conditions include, but are not limited to, ambient air temperature, humidity, barometric pressure, intake water temperature, and cooling system performance. Generating units with the ability to operate continuously across all hours of an Operating Day without interruption if needed include, but are not limited to, nuclear and fossil-fired steam units, combined cycle units, combustion turbine units, reciprocating engine units, and fuel cell units.

For ELCC Resources, the Office of the Interconnection shall determine the capability of the resource to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.1, with additional implementation details provided in the PJM Manuals.

D. For the 2025/2026 Delivery Year and Subsequent Delivery Years

The Office of the Interconnection shall determine the capability of Generation Capacity Resources to meet a Load Serving Entity's obligations under the Agreement using an effective load carrying capability analysis, as set forth in RAA, Schedule 9.2, with additional implementation details provided in the PJM Manuals.

SCHEDULE 9.1:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR DELIVERY YEARS THROUGH THE 2024/2025 DELIVERY YEAR

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources and Combination Resources.

The outputs of the effective load carrying capability analysis include:

-The ELCC Portfolio UCAP, in MW;
-ELCC Class UCAP values, in MW; and
-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)
- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)

- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified below

(2) PJM shall establish Hybrid Resource Classes for all “open-loop” combinations of each Capacity Storage Resource class and each Variable Resource class, as well as all “closed-loop” combinations of each Capacity Storage Resource class and each Variable Resource class. An “open-loop” resource is physically and contractually capable of charging from the grid, while a “closed-loop” resource is not.

(3) PJM shall establish “Other Limited Duration Combination Classes” for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or
(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or
(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Portfolio UCAP

The effective load carrying capability analysis shall identify a scenario in which the aggregate installed capacity “Y” of a group of Unlimited Resources with no outages yields the same annual loss of load expectation as the one produced by the scenario with all ELCC Resources that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed. The ELCC Portfolio UCAP shall be the value “Y”.

D. Allocation from ELCC Portfolio UCAP to ELCC Class UCAP

The ELCC Portfolio UCAP shall be allocated, as specified in the PJM Manuals, to each ELCC Class UCAP according to:

(1) The reliability value of the subject ELCC Class evaluated in the absence of other ELCC Classes, minus

(2) a quantity that is proportional to the product of:

> (a) the difference between the reliability value of the subject ELCC Class when evaluated in the presence of the entire portfolio of ELCC Classes and the reliability value of the subject ELCC Class when evaluated in the absence of the other ELCC Classes, and
>
> (b) the difference between the total reliability value of all the ELCC Classes in the model when evaluated jointly and the sum of the reliability values determined individually for each ELCC Class by evaluating the subject ELCC Class in the absence of other ELCC Classes.

E. Calculation of ELCC Class Rating

(1) The ELCC Class Rating of Variable Resources and Limited Duration Resources shall be the ratio of the applicable ELCC Class UCAP to the aggregate Effective Nameplate Capacity of the modeled ELCC Resources of that ELCC Class that are expected to offer in a given RPM Auction, or otherwise provide capacity, in the Delivery Year being analyzed.

(2) For Combination Resources, there shall be an ELCC Class Rating for each component.

> (i) For a Combination Resource with a Limited Duration Resource component and a Variable Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the quotient of (1) the Combination Resource ELCC Class UCAP minus the [product of the Variable Resource ELCC Class Rating and the aggregate Effective Nameplate Capacity of all the Variable Resource components within the subject Combination Resource class] divided by (2) the aggregate equivalent Effective Nameplate Capacity of all the Limited Duration Resource components within the subject Combination Resource class, and the Variable Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Variable Resource component would belong if it were not a component of the Combination Resource.
>
> (ii) For a Combination Resource with a Limited Duration Resource component and an Unlimited Resource component, the Limited Duration Resource component ELCC Class Rating shall be equal to the ELCC Class Rating for the ELCC Class to which the Limited Duration Resource component would belong if it were not a component of the Combination Resource, and the Unlimited Resource component would not have an ELCC Class Rating.

(3) For ELCC Resources in the Hydropower with Non-Pumped Storage Class and in the Complex Hybrid Class, no ELCC Class Rating is determined. A resource-specific ELCC rating is determined for each such resource.

F. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For Combination Resources, Accredited UCAP values shall be equal to the sum of the Accredited UCAP of each component, but not to exceed the Maximum Facility Output of the resource, where:

(i) The value for a Variable Resource component shall be determined in accordance with subsection (a) above.

(ii) The value for a Limited Duration Resource component shall be equal to the product of:

(A) the Effective Nameplate Capacity determined for the Limited Duration Resource component;

(B) [one minus the EFORd for the Limited Duration Resource component]; and

(C) the applicable Limited Duration Resource component ELCC Class Rating as determined in Section E(2)(i).

(iii) The value for an Unlimited Resource component shall be equal to the product of the installed capacity of the Unlimited Resource component and [one minus the EFORd for the Unlimited Resource component].

(iv) The Accredited UCAP for Hydropower With Non-Pumped Storage, and for each member of an ELCC Class whose members are so distinct from one another that a single ELCC Class Rating fails to capture their physical characteristics, shall be based on a resource-specific effective load carrying capability analysis based on the resource’s unique parameters.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource: based on a metric consisting of the average of (1) actual output during the 200 highest coincident peak load hours over the preceding ten years, regardless of the years in which they occur, and (2) actual output during the 200 highest coincident peak putative net load hours over the preceding ten years, regardless of the years in which they occur, where putative net load is actual load minus the putative hourly output of Variable Resources based on the resource mix of the target year. For Planned Resources or resources less than 10 years old, estimated hypothetical historical output will be used to develop this metric. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class.

(b) For Limited Duration Resources: based on EFORd.

(c) For Combination Resources with only an Unlimited Resource component and a Limited Duration Resource component: based on EFORd.

(d) For Combination Resources with a Variable Resource component (except for Hydropower With Non-Pumped Storage): (1) based on the direct metered or estimated output of the Variable Resource component, which is then assessed according to the methodology described in subsection (a) above for Variable Resources and in accordance with the PJM Manuals; and (2) based on the EFORd that is applicable to the Limited Duration Resource component.

(e) For Hydropower With Non-Pumped Storage and other Combination Resources that do not fall into the above categories: based on EFORd.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative resource adequacy value of the portfolio of all ELCC Classes, as well of each individual ELCC Class, compared to a group of Unlimited Resources with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual loss of load expectation of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; and (iii) expected output of Limited Duration Resources and of Combination Resources as described below. These expected quantities are based on actual values for load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. This putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals.

The effective load carrying capability analysis shall simulate forced outages of Unlimited Resources based on actual historical data, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above. Forced outages of Limited Duration Resources and Combination Resources shall not be simulated in the effective load carrying capability analysis.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year.

The ELCC Class UCAP and other results of the effective load carrying capability analysis shall be based on the total Effective UCAP of the ELCC Class as a whole.

The ELCC Class UCAP and corresponding ELCC Class Rating values may increase or decrease from year to year as the expected resource mix and load shape change.

Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources and Combination Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis in proportion to their Effective Nameplate Capacity without foresight to future hours. The simulated deployment of Demand Resources shall be such that there is adequate Primary Reserves provided by economic resources, if sufficient simulated Demand Resources are available. Primary Reserves shall be assigned to generation resources in order to maximize simulated reliability, provided that assignments to Limited Duration Resources and Combination Resources shall be pro rata according to their Effective Nameplate Capacity. Primary Reserves shall be exhausted prior to identifying a loss of load event in the analysis. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Starting with the 2023/2024 Delivery Year, Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 15 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for Delivery Years prior to the 2026/2027 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection's determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 9.2:

EFFECTIVE LOAD CARRYING CAPABILITY ANALYSIS FOR THE 2025/2026 DELIVERY YEAR AND SUBSEQUENT DELIVERY YEARS

A. Overview of Effective Load Carrying Capability Analysis

The inputs of the effective load carrying capability analysis shall consider similar data and forecasts as that used in development of the FPR, as described in Schedule 4.C, and will include:

-Historical weather and load data;
-Historical output of existing Variable Resources;
-Estimates of putative historical output for planned Variable Resources;
-Forced outage patterns for Unlimited Resources, including consideration of correlated outage risks;
-Resource deployment forecast; and
-Modeling parameters for Limited Duration Resources, Combination Resources, and Demand Resources.

The outputs of the effective load carrying capability analysis include:

-ELCC Class Rating values, in percent.

B. ELCC Classes

(1) (a) The following are the ELCC Classes for Variable Resources:

- Tracking Solar Class
- Fixed-Tilt Solar Class
- Onshore Wind Class
- Offshore Wind Class
- Intermittent Landfill Gas Class
- Intermittent Hydropower Class
- Other Variable Resource Class

(b) The following are the types of ELCC Classes for Limited Duration Resources:

- The type of Capacity Storage Resource Classes
- The type of Other Limited Duration Resource Classes

Within those types, the following are the specific ELCC Classes for Limited Duration Resources:

- Capacity Storage Resource Class (4-Hour Duration)
- Capacity Storage Resource Class (6-Hour Duration)
- Capacity Storage Resource Class (8-Hour Duration)
- Capacity Storage Resource Class (10-Hour Duration)

- Other Limited Duration Class (4-Hour Duration)
- Other Limited Duration Class (6-Hour Duration)
- Other Limited Duration Class (8-Hour Duration)
- Other Limited Duration Class (10-Hour Duration)

(c) The following are the ELCC Classes for Combination Resources:

- The types of Hybrid Resource Classes, as further specified in subpart (2) below
- Hydropower With Non-Pumped Storage Class
- Complex Hybrid Class
- The types of Other Limited Duration Combination Classes, as further specified in subpart (3).

(d) The following are the ELCC Classes for Unlimited Resources

- Nuclear Class
- Coal Class
- Gas Combined Cycle Class
- Gas Combustion Turbine Class
- Gas Combined Cycle Dual Fuel Class
- Oil Fired Combustion Turbine Class (effective with the 2027/2028 Delivery Year)
- Gas Combustion Turbine Dual Fuel Class
- Diesel Utility Class
- Other Steam Class
- Waste to Energy Steam Class (effective with the 2027/2028 Delivery Year)
- Other Unlimited Resource Class

(e) The following are the ELCC Classes for Demand Resources

- Demand Resource Class

(2) PJM shall establish Hybrid Resource Classes for all “open-loop” combinations of each Capacity Storage Resource class and each Variable Resource class or Unlimited Resource class, as well as all “closed-loop” combinations of each Capacity Storage Resource class and each Variable Resource class or Unlimited Resource class. An “open-loop” resource operates by charging the storage component from the grid, while a “closed-loop” resource does not.

(3) PJM shall establish “Other Limited Duration Combination Classes” for all combinations of each Variable Resource Class and each Other Limited Duration Resource Class, and for combinations of an Unlimited Resource with each Other Limited Duration Resource Class.

(4) For a given Delivery Year, ELCC Class Ratings will not be calculated for any ELCC Class to the extent that no member of the class is expected to provide, or offer to provide capacity, in the applicable Delivery Year. PJM will determine the ELCC Class Ratings for an ELCC Class when any one of the following criteria are met:

(a) An Existing Generation Capacity Resource is in such class; or

(b) A Planned Generation Capacity Resource has submitted timely and valid data through the ELCC data submission process and is in such class; or

(c) The resource deployment forecast contains a resource in such class.

(5) (a) For each ELCC Resource, except an ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine the ELCC Class of which such resource is a member by matching the physical characteristics of such resource with the definition of the ELCC Class.

(b) For each ELCC Resource that is a Capacity Storage Resource or includes a Capacity Storage Resource component, PJM shall determine, by matching the physical characteristics of such resource with the definition of the ELCC Class, the type of ELCC Class of which such resource is a member; provided however, the Generation Capacity Resource Provider shall choose the specific ELCC Class within the type ELCC Class identified by PJM that corresponds to the chosen characteristic duration.

If the Generation Capacity Resource Provider fails to choose, PJM will choose a specific ELCC Class to assign to such resource. The election of the specific ELCC Class corresponding to the chosen characteristic duration shall be for a term of five consecutive Delivery Years. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in the ELCC Class, based on choosing a different characteristic duration, by submitting to the Office of the Interconnection a written request to switch ELCC Classes and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource shall be considered in the new ELCC Class starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

(6) Mixed-technology resources are composed of components with different generation technologies, at least one of which would be an ELCC Resource, behind a single Point of Interconnection. For a mixed-technology resource composed of components that do not have significant interaction, the components are eligible to participate as separate resources. A mixed-technology resource composed of components that have significant interaction must participate as a single Combination Resource (or, if the components would all be Variable Resources, then as a single Variable Resource).

The Generation Capacity Resource Provider of a mixed-technology resource eligible to participate as either a single ELCC Resource or as multiple stand-alone resources shall elect, for a term of five consecutive Delivery Years, whether PJM is to model it as a single ELCC Resource or as multiple stand-alone resources. After such five Delivery Year period, a Generation Capacity Resource Provider may request a change in such modelling approach by submitting to the Office of the Interconnection a written request to change the modelling approach and provide documentation supporting such change. A Generation Capacity Resource Provider must submit such a request, and supporting documentation, by August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource(s) intend(s) to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Year such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The Office of the Interconnection shall provide no later than following November 15 written notification to the Generation Capacity Resource Provider of its determination. If the request is granted, the ELCC Resource(s) shall be modelled as requested starting with the next Delivery Year for which no RPM Auction has been conducted and for subsequent Delivery Years. If the request is denied, the Office of the Interconnection shall include in the notice a written explanation for the denial.

C. Calculation of ELCC Class Rating

ELCC Class Ratings for a Delivery Year are calculated by adding to the forecasted resource portfolio incremental quantities of resources belonging to the subject ELCC Class, depending on the resource type:

(1) The ELCC Class Rating of Variable Resources, Limited Duration Resources, Unlimited Resources (except Other Unlimited Resources), and Demand Resources shall be the ratio of the expected unserved energy improvement resulting from adding an incremental quantity of the subject ELCC Class to the expected unserved energy improvement resulting from adding an incremental quantity of an Unlimited Resource with no outages, where expected unserved energy improvement is calculated relative to the Portfolio EUE for the Delivery Year.

(2) No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

D. Calculation of Accredited UCAP and ELCC Resource Performance Adjustment

(1) (a) For Variable Resources and Limited Duration Resources, Accredited UCAP values shall be equal to the lesser of the resource's Capacity Interconnection Right or the product of:

(i) the Effective Nameplate Capacity;
(ii) the applicable ELCC Class Rating; and
(iii) the ELCC Resource Performance Adjustment.

(b) For any resource in an ELCC Class for which no Class Rating has been calculated pursuant to C(2), the Accredited UCAP shall be based on a resource-specific effective load carrying capability analysis based on the resource's unique parameters.

(c) For Unlimited Resources that have an ELCC Class Rating determined pursuant to C(1), Accredited UCAP values shall be equal to the product of:

(i) the installed capacity;
(ii) the applicable ELCC Class Rating; and

(iii) the ELCC Resource Performance Adjustment.

(d) For Demand Resources, Accredited UCAP values shall be equal to the product of:

(i) the Nominated Value of the Demand Resource; and
(ii) the applicable ELCC Class Rating.

(2) The ELCC Resource Performance Adjustment shall be calculated according to the following methods, as further detailed in the PJM Manuals:

(a) For a Variable Resource, a Limited Duration Resource, and an Unlimited Resource: based on a metric consisting of the weighted average expected hourly output of the resource in the ELCC model during hours of loss of load risk where: (i) the weights correspond to the modeled probability of losing load in such hour and (ii) the expected hourly output is based on the resource's modeled output during the same hour on days since June 1st, 2012 identified as having similar weather from an RTO-perspective. For a given resource or component, the Performance Adjustment shall equal the ratio of such metric to the average (weighted by the Effective Nameplate Capacity) of such metrics for all units in the applicable Variable Resource ELCC Class or applicable Unlimited Resource ELCC Class.

In determining the ELCC Resource Performance Adjustment, the actual output of a Variable Resource shall be adjusted to reflect historical curtailments, and output in any hour shall be capped at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, for hours in the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, for hours in the months of November through April of the Delivery Year. The output of an Unlimited Resource in any hour shall be capped at the greater of the resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year..

E. Calculation of Accredited UCAP Factor

For Generation Capacity Resources, PJM shall determine an Accredited UCAP Factor, which is the ratio of the resource's Accredited UCAP to the resource's installed capacity.

G. Installed Capacity of ELCC Resources

Rules and procedures for technically determining and demonstrating the installed capacity of ELCC Resources shall be developed by the Office of the Interconnection and maintained in the PJM Manuals. The installed capacity of a Limited Duration Resource is based on the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, as described in the PJM Manuals. The installed capacity of a Combination Resource (other than Hydropower With Non-Pumped Storage) is based on the lesser of the Maximum Facility

Output or the sum of the equivalent Effective Nameplate Capacity values of the resource's constituent components considered on a stand-alone basis. The installed capacity of an Unlimited Resource and Variable Resource shall be determined in accordance with the PJM Manuals. The installed capacity of Demand Resources, for purposes of the ELCC analysis, is based on the forecasted deployment level in the PJM Load Forecast.

H. Details of the Effective Load Carrying Capability Methodology

The effective load carrying capability analysis shall compare expected hourly load levels (based on historical weather) with the expected hourly output of the expected future resource mix in order to identify the relative marginal resource adequacy value of each individual ELCC Class compared to an Unlimited Resource with no outages. In performing this analysis, the model inputs shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The effective load carrying capability analysis shall compare hourly values for: (i) expected load based on historical weather; (ii) expected Variable Resource output; (iii) expected output of Limited Duration Resources and of Combination Resources as described below; (iv) expected Unlimited Resource output; and (v) expected Demand Resource output. These expected quantities are based on forecasted load and actual and putative values for Variable Resource output (standalone or as a component of Combination Resources) and Unlimited Resource output after June 1, 2012 (inclusive) through the most recent Delivery Year for which complete data exist. For resources that have not existed each year since June 1, 2012, putative output is an estimate of the hourly output that resource would have produced in a historical hour if that resource had existed in that hour. For Variable Resources, this putative output estimate is developed based on historical weather data consistent with the particular site conditions for each such resource in accordance with the PJM Manuals; for Unlimited Resources, the putative output is developed based on actual performance of similar units in accordance with the PJM Manuals.

Variable Resource actual output shall be adjusted in the ELCC analysis to reflect historical curtailments, and output shall be capped in any hour at: (i) the greater of the Variable Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Variable Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. The output of Unlimited Resources shall not exceed the greater of the Unlimited Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

The effective load carrying capability analysis shall simulate performance of Demand Resources, and shall simulate the output of Limited Duration Resources and Combination Resources based on their Office of the Interconnection-validated parameters, including the putative output of the Variable Resource component of Combination Resources, as described above.

The quantity of deployed resources studied in the analysis shall be based on resource deployment forecasts and, where applicable, on available information based on Sell Offers submitted in RPM Auctions or Fixed Resource Requirement plans for the applicable Delivery Year, and, where applicable, information provided to the Office of the Interconnection regarding intent to offer in an RPM Auction, pursuant to the requirements in the Tariff, Attachment DD, section 5.5.

The model inputs, specifically the load scenarios, shall be scaled to meet the annual reliability criteria of the Office of the Interconnection. The resulting expected unserved energy constitutes the Portfolio EUE for the Delivery Year. Energy Resources are not included in the effective load carrying capability analysis. Generating units that are expected to only offer or otherwise provide a portion of their Accredited UCAP for that Delivery Year are represented in the analysis in proportion to the expected quantity offered or delivered divided by the Accredited UCAP.

I. Methodology to Simulate Output of Certain Resources in the Effective Load Carrying Capability Model

The effective load carrying capability analysis shall simulate the output of Limited Duration Resources and Combination Resources based on their physical parameters, including limited storage capability, and shall simulate the deployment of Demand Resources. The analysis shall simulate output from the subject Limited Duration Resources, Combination Resources, and Demand Resources in hours in which all output from Unlimited Resources and available output from Variable Resources is insufficient to meet load. The analysis shall first simulate the output of Demand Resources. If the simulated output of Demand Resources is insufficient to meet load, then the output of the subject Limited Duration Resources and Combination Resources shall be simulated on an hour-by-hour basis based on their relative duration, starting from longer duration resources to shorter duration resources. The output of Combination Resources shall be capped in any hour at: (i) the greater of the Combination Resource's Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year, during the months of June through October and the following May of the Delivery Year, and (ii) the Combination Resource's assessed deliverability, as defined in the PJM Manuals, during the months of November through April of the Delivery Year. Energy Storage Resource charging is during hours with sufficient margin, including between daily peaks if necessary.

J. Administration of Effective Load Carrying Capability Analysis

The Office of the Interconnection shall post final ELCC Class Rating values at least once per year in a report that also includes appropriate details regarding methodology and inputs. The Office of the Interconnection shall post this report and shall communicate ELCC Resource Performance Adjustment values to applicable Generation Capacity Resource Providers no later than five months prior to the start of the target Delivery Year, as described in the PJM Manuals. Accredited UCAP values for the applicable Delivery Year shall establish the maximum Unforced Capacity that an ELCC Resource can physically provide or offer to provide in the applicable Delivery Year.

The Office of the Interconnection shall also post preliminary ELCC Class Rating values for nine subsequent Delivery Years. For any Delivery Year for which a final ELCC Class Rating has not been posted and a preliminary ELCC Class Rating has been posted, the Accredited UCAP of an ELCC Resource for such Delivery Year shall be based on the most recent preliminary ELCC Class Rating value for that Delivery Year, together with the most recently calculated ELCC Resource Performance Adjustment value for that ELCC Resource. Except to the extent specified above or otherwise specified, the preliminary ELCC Class Rating values for future years are non-binding and are only for indicative purposes. A Generation Capacity Resource Provider can offer or provide capacity from an ELCC Resource that is not subject to a capacity market must offer obligation (as specified in Tariff, Attachment DD, Section 6.6) at a level less than the Accredited UCAP for such resource.

In order to facilitate the effective load carrying capability analysis, the Generation Capacity Resource Provider of each ELCC Resource must submit to the Office of the Interconnection the required information as specified in the PJM Manuals by no later than August 1 prior to the calendar year for the RPM Auction in which the ELCC Resource intends to submit a Sell Offer or otherwise commit to provide capacity, except for 2025/2026 Delivery Years such required information must be provided to the Office of the Interconnection in accordance with the PJM Manuals. The required information may include relevant physical parameters, relevant historical data such as weather data and actual or estimated historical energy output, and documentation supporting such parameters and historical data. The relevant physical parameters are those that are incorporated into the effective load carrying capability analysis. The parameters required for Hydropower With Non-Pumped Storage shall include Ordinary Water Storage and any applicable Exigent Water Storage. Submitted parameters must indicate the expected duration for which any submitted physical parameters are valid.

The Office of the Interconnection shall evaluate, validate, and approve the foregoing information in accordance with the process set forth in the PJM Manuals. In evaluating the validity of submitted information, the Office of the Interconnection may assess the consistency of such information with observed conditions. If the Office of the Interconnection observes that the information provided by the Generation Capacity Resource Provider of the ELCC Resource is inconsistent with observed conditions, the Office of the Interconnection will coordinate with the Generation Capacity Resource Provider of the ELCC Resource to understand the information and observed conditions before making a determination regarding the validity of the applicable parameters. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the foregoing information.

After the Office of the Interconnection has completed its evaluation of the foregoing information, the Office of the Interconnection shall notify the Generation Capacity Resource Provider in writing whether the submitted information is considered invalid by no later than September 1 following the submission of the information. The Office of the Interconnection’s determination on the validity of the foregoing information shall continue for the applicable Delivery Year and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

In the event that the Office of the Interconnection is unable to validate any of the required information, physical parameters, supporting documentation, or other related information submitted by the Generation Capacity Resource Provider of an ELCC Resource, then the Office of the Interconnection shall calculate Accredited UCAP values for that ELCC Resource based only on the validated information. Such ELCC Resource shall not be permitted to offer or otherwise provide capacity above such Accredited UCAP values until the Office of the Interconnection determines new Accredited UCAP values for such resource.

Generation Capacity Resource Providers of ELCC Resources that are hydropower plants with water storage must provide documentation to support the physical parameters provided for expected load carrying capability analysis modeling, as specified in the PJM Manuals. This documentation must: (a) support the plant's physical capabilities; (b) demonstrate that the parameters do not violate any federal, state, river basin, or other applicable authority operating limitations of the plant; and (c) demonstrate full authorization from FERC, any river basin commissions, and any other applicable authorities to meet those capabilities.

SCHEDULE 10

PROCEDURES FOR ESTABLISHING
DELIVERABILITY OF GENERATION CAPACITY RESOURCES

Generation Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by obtaining or providing for Network Transmission Service within the PJM Region such that each Generation Capacity Resource is a Network Resource. In addition, for Generation Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Unforced Capacity Obligation, the capacity and energy of such Generation Capacity Resources must comply with the deliverability requirements of PJM Tariff, Attachment DD, section 5.5A, and the receipt of such capacity and energy at the PJM Region interface for delivery to loads in the PJM Region shall be subject to all applicable Capacity Import Limits.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Generation Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in RAA, Schedule 15), combinations of such Zones, and portions of such Zones:

- EKPC
- Cleveland
- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Region (MAR) (consisting of all the zones listed below for Eastern MAR (EMAR), Western MAR (WMAR), and Southwestern MAR (SWMAR))
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, DEOK, EKPC, and OVEC
- EMAR (PSE&G, JCP&L, PECO, AE, DPL & RE)
- SWMAR (PEPCO & BG&E)
- WMAR (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into

PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a CETL less than 1.15 times the CETO of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

SCHEDULE 12

DATA SUBMISSION CHARGES

A. Data Submission Charge

For each working day of delay in the submittal of information required to be submitted under this Agreement, a data submission charge of $500 shall be imposed.

B. Distribution Of Data Submission Charge Receipts

1. Each Party that has satisfied its obligations for data submittals pursuant to RAA, Schedule 11 during a Delivery Year, without incurring a data submission charge related to that obligation, shall share in any data submission charges paid by any other Party that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the sum of the Unforced Capacity Obligations of each such Party entitled to share in the data submission charges for the most recent month.

2. In the event all of the Parties have incurred a data submission charge during a Delivery Year, those data submission charges shall be distributed as approved by the PJM Board.

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

(b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

(c) Monitor the compliance of each Party with its obligations under the Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

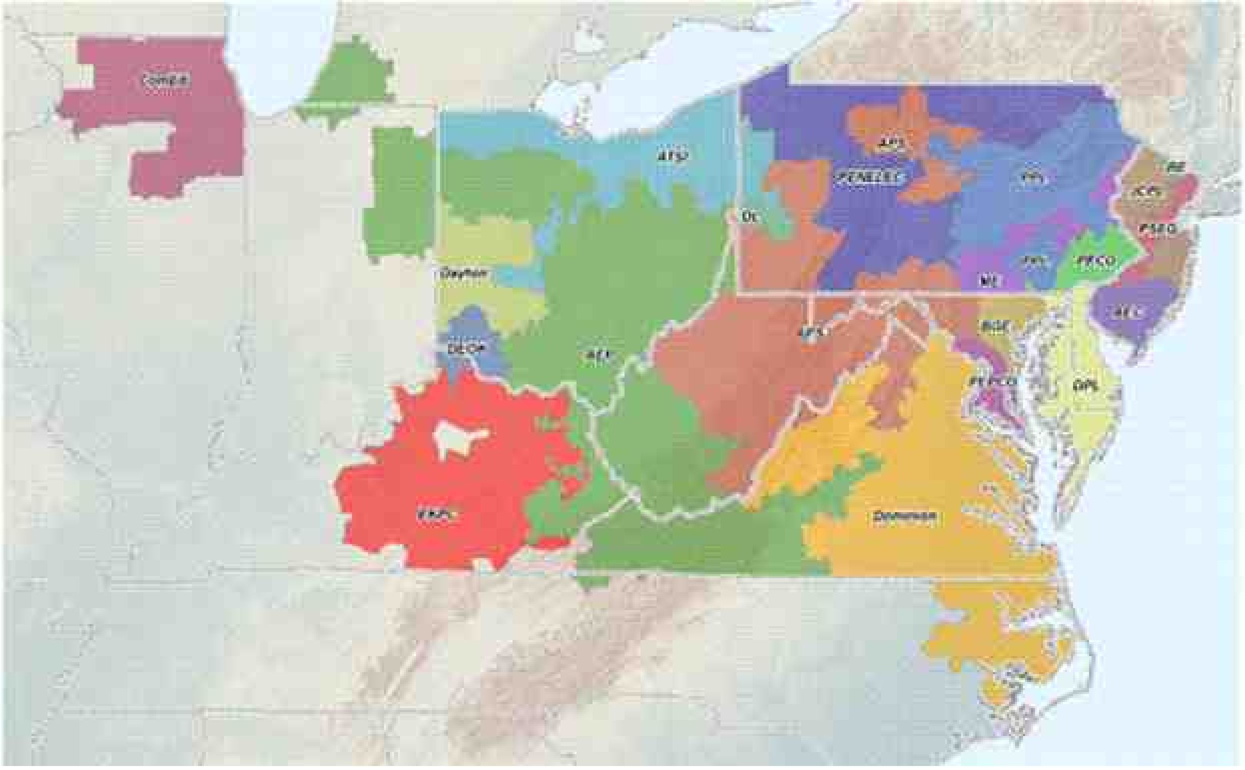
(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Entity principles, guidelines, standards, requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

SCHEDULE 15
ZONES WITHIN THE PJM REGION



FULL NAME **SHORT NAME**

Pennsylvania Electric Company* ....Penelec
Allegheny Power ....APS
PPL Group ....PPL
Metropolitan Edison Company** ....MetEd
Jersey Central Power and Light Company ....JCPL
Public Service Electric and Gas Company ....PSEG
Atlantic City Electric Company ....AEC
PECO Energy Company ....PECO
Baltimore Gas and Electric Company ....BGE
Delmarva Power and Light Company ....DPL
Potomac Electric Power Company ....PEPCO
Rockland Electric Company ....RE
Commonwealth Edison Company ....ComEd
AEP East Zone ....AEP
The Dayton Power and Light Company ....Dayton
Virginia Electric and Power Company ....Dominion
Duquesne Light Company ……………………………………………........DL
American Transmission Systems, Incorporated ………………………ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.……………DEOK
East Kentucky Power Cooperative, Inc. ………………………………EKPC
Ohio Valley Electric Corporation ……………………………………..OVEC

* FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Pennsylvania Electric Company, but all references to the Pennsylvania Electric Company or Penelec Zone remain unchanged.

** FirstEnergy Pennsylvania Electric Company (“FE PA”) is the successor-in-interest to Metropolitan Edison Company, but all references to the Metropolitan Edison Company or MetEd Zone remain unchanged.

SCHEDULE 16

Non-Retail Behind the Meter Generation Maximum Generation Emergency Obligations

1. A Non-Retail Behind The Meter Generation resource that has output that is netted from the Daily Unforced Capacity Obligation of a Party pursuant to RAA, Schedule 7 shall be required to operate at its full output during the first ten times between November 1 and October 31 that Maximum Generation Emergency conditions occur in the zone in which the Non-Retail Behind The Meter Generation resource is located.

2. The Party for which Non-Retail Behind The Meter Generation output is netted from its Daily Unforced Capacity Obligation shall be required to report to PJM scheduled outages of the resource prior to the occurrence of such outage in accordance with the time requirements and procedures set forth in the PJM Manuals. Such Party also shall report to PJM the output of the Non-Retail Behind The Meter Generation resource during each Maximum Generation Emergency condition in which the resource is required to operate in accordance with the procedures set forth in PJM Manuals.

3. Except for failures to operate due to scheduled outages during the months of October through May, for each instance a Non-Retail Behind The Meter Generation resource fails to operate, in whole or in part, as required in paragraph 1 above, the amount of operating Non-Retail Behind The Meter Generation from such resource that is eligible for netting will be reduced pursuant to the following formula:

$$\text{Adjusted ENRBTMG} = \text{ENRBTMG} - \sum (10\% \text{ of the Not Run NRBTMG})$$

Where:

ENRBTMG equals the operating Non-Retail Behind The Meter Generation eligible for netting as determined pursuant to RAA, Schedule 7.

Not Run NRBTMG is the amount in megawatts that the Non-Retail Behind The Meter Generation resource failed to produce during an occurrence of Maximum Generation Emergency conditions in which the resource was required to operate.

∑ (10% of the Not Run NRBTMG) is the summation of 10% megawatt reductions associated with the events of non-performance.

The Adjusted ENRBTMG shall not be less than zero and shall be applicable for the succeeding Planning Period.

4. If a Non-Retail Behind The Meter Generation resource that is required to operate during a Maximum Generation Emergency condition is an Energy Resource and injects energy into the Transmission System during the Maximum Generation Emergency condition, the Network

Customer that owns the resource shall be compensated for such injected energy in accordance with the PJM market rules.

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Energy, Inc.
AEP Retail Energy Partners LLC
AES Ohio Generation, LLC
AES Solutions Management, LLC
Aggressive Energy LLC
Agway Energy Services, LLC
Algonquin Energy Services Inc.
All American Power and Gas, LLC
All Choice Mid America LLC dba Raava Energy
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpaca Energy LLC
Alpha Gas and Electric LLC
Ambit Northeast, LLC
American Electric Power Service Corporation on behalf of its affiliates:
    Appalachian Power Company
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Municipal Power, Inc.
American Power & Gas of IL, LLC
American Power & Gas of MD, LLC
American Power & Gas of NJ, LLC
American Power & Gas of Ohio, LLC
American Power & Gas of Pennsylvania, LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
Ameripro Energy Corp.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
Approved Energy II LLC
Archer Energy, LLC
Astral Energy LLC
Atlantic City Electric Company
Atlantic Energy MD, LLC
Avangrid Renewables, LLC
Axpo U.S. LLC
Baltimore Gas and Electric Company

Baltimore Power Company LLC
Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Columbia, PA
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey
Borough of Pemberton
Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
Boston Energy Trading and Marketing LLC
BP Energy Company
BP Energy Retail Company LLC
Brookfield Renewable Energy Marketing US LLC
BTG Pactual Commodities (US) LLC
Buckeye Power, Inc.
Calpine Energy Service, L.P.
Calpine Energy Solutions, LLC
Catalyst Power & Gas LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Choice Energy, LLC dba 4 Choice Energy, LLC
Citigroup Energy Inc.
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of New Martinsville - WV
City of Rochelle
CleanChoice Energy, Inc.
Clearview Electric, Inc.
Cleveland Electric Illuminating Company
Click Energy, LLC
CMS Resource Management Company
Collegiate Clean Energy, LLC
Commonwealth Edison Company
ConocoPhillips Company
Constellation Energy Generation, LLC

Constellation NewEnergy, Inc.
CPV Retail Energy LP
Current Energy and Renewables Inc.
David Energy Supply, LLC
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Power, Inc.
DPL Energy Resources, Inc.
DRW Energy Trading, LLC
DTE Atlantic, LLC
DTE Energy Trading, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Duquesne Light Energy, LLC
DXT Commodities North America Inc.
Dynegy Energy Services, LLC
Dynegy Marketing and Trade, LLC
East Kentucky Power Cooperative, Inc.
Easton Utilities Commission
EcoPlus Power, LLC
EDF Trading North America, LLC
Eligo Energy, LLC
Enel Trading North America, LLC
Energetix, Inc.
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy Harbor LLC
EnergyMark, LLC
Energy Plus Holdings LLC
Energy Services Providers, LLC
Energy Technology Savings, Inc.
Energy Transfer Retail Power, LLC
EnerPenn USA, LLC
Engie Energy Marketing NA, Inc.
Evergreen Gas & Electric, LLC
Everyday Energy, LLC
FirstEnergy Pennsylvania Electric Company
First Point Power, LLC
Five Elements Energy II, LLC

Freepoint Energy Solutions LLC
Front Royal (Town of)
Galt Power Inc.
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
Great American Gas & Electric, LLC
Great American Power, LLC
Greenlight Energy Inc.
Green Mountain Energy Company
Hagerstown Light Department
Harborside Energy, LLC
Harrison REA, Inc. - Clarksburg, WV
Hartee Parnters, LP
Holcim (US) Inc.
Hoosier Energy REC, Inc.
Horizon Power and Light LLC
Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
Illinois Power Marketing Company
Inspire Energy Holdings, LLC
Interstate Gas Supply, LLC
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
J. Aron & Company LLC
Jersey Central Power & Light Company
Just Energy Limited
Kentucky Municipal Energy Agency
Kiwi Energy NY LLC
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Land O’Lakes, Inc.
Macquarie Energy LLC
Major Energy Electric Services LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
Median Energy Corp.
Median Energy PA LLC
Mercuria Energy America, Inc.
Messer Energy Services, Inc.
MidAmerican Energy Company
MidAmerican Energy Services, LLC
Morgan Stanley Capital Group, Inc.

Morgan Stanley Services Group Inc.
MP2 Energy NE, LLC dba Shell Energy Solutions
MPower NJ LLC
National Gas & Electric, LLC
NextEra Energy Marketing, LLC
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northeastern REMC
Northern States Power Company
Northern Virginia Electric Cooperative – NOVEC
NRG Business Marketing LLC
NRG Power Marketing, L.L.C.
nTherm, LLC
Octopus Energy LLC
Ohio Edison Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
Palmco Power DC, LLC
PALMco Power DE, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power PA, LLC
PALMco Power VA, LLC
Park Power LLC
Pay Less Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Grain Processing LLC
PEPCO Energy Services, Inc.
Plymouth Rock Energy, LLC
Polaris Power Services LLC
Potomac Electric Power Company
Power UP Energy, LLC
Powervine Energy, LLC
PPL Electric Utilities Corporation d/b/a PPL Utilities
Prairieland Energy, Inc.
Provision Power and Gas, LLC
PSEG Energy Resources & Trade LLC
PSEG Energy Solutions LLC
Public Service Electric and Gas Company
Pure Energy USA IL, LLC

Pure Energy USA, LLC
Realgy, LLC
Red Oak Power, LLC
Renaissance Power & Gas, Inc.
ResCom Energy, LLC
Residents Energy, L.L.C.
Respond Power LLC
ReWorld REC, LLC
Riverside Generating Company, LLC
Rolling Hills Generating, LLC
RPA Energy, Inc.
Rushmore Energy, LLC (new)
RWE Clean Energy Solutions, Inc.
S.J. Energy Partners, Inc.
Santanna Energy Services
Seward Generation, LLC
SFE Energy, Inc.
Shipley Choice LLC
Smartest Energy US LLC
Solios Power Mid-Atlantic Trading LLC
South Bay Energy Corp.
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, LLC
Spartacus Energy Services LLC
Spring Energy RRH, LLC dba Spring Power & Gas
Standard Gas & Electric, LLC
Stream Energy Columbia, LLC
Stream Energy Delaware, LLC
Stream Energy Illinois, LLC
Stream Energy Maryland, LLC
Stream Energy New Jersey, LLC
Stream Energy Pennsylvania, LLC
Stream Ohio Gas & Electric, LLC
Summer Energy Midwest, LLC
SunSea Energy LLC
Talen Energy Marketing, LLC
Tenaska Power Services Co.
Texas Retail Energy, LLC
Think Energy, LLC
Titan Gas and Power
Toledo Edison Company (The)
Tomorrow Energy Corp
Town of Berlin, Maryland
Town of Thurmont

Town of Williamsport
Town Square Energy East, LLC
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trustees of the University of Pennsylvania
Twin Eagle Resource Management, LLC
UGI Energy Services, LLC
UGI Utilities, Inc. - Electric Division
U.S. Power Supply, LLC
Verde Energy USA DC, LLC
Verde Energy USA Illinois, LLC
Verde Energy USA Maryland, LLC
Verde Energy USA Ohio, LLC
Verde Energy USA, Inc.
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Viridian Energy Ohio LLC
Vista Energy Marketing, L.P.
Volunteer Energy Services, Inc.
Wabash Valley Power Association, Inc.
Wellsboro Electric Company
WestRock MWV, LLC
WGL Energy Services, Inc.
Wolverine Holdings, L.P.
Wolverine Power Supply Cooperative, Inc.
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
XOOM Energy Ohio, LLC
Xoom Energy, LLC
York Generation Company, LLC