

PJM Manual 14A:

New Services Request Process

Revision: 2022

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Prepared by
Interconnection Planning Department

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Approval

Approval Date: ~~10/27/2017~~ 01/01/2018
Effective Date: ~~10/01/2017~~ 01/01/2018

Dave Egan, Manager

Generation Interconnection

Current Revision**Revision 22 (XX/XX/2018):**

- Revised to add additional clarity concerning analyses performed during various stages of project studies
 - o Section 2.1.6 revised
 - o Section 2.2.2 revised
 - o Section 2.3.2 title revised
 - o Section 2.3.3 title revised
 - o Section 2.3.4 revised
 - o Section B.3.2 of Attachment B revised to add clarity
 - o Section B.3.5 of Attachment B revised to add clarity

~~Revision 21 (XX/XX/2018):~~

- ~~Revised to add additional clarity concerning analyses performed during various stages of project studies~~
 - o ~~Section 2.1.7 added~~
 - o ~~Section 2.2.2 revised~~
 - o ~~Section 2.3.4 revised~~
 - o ~~Section B.3 of Attachment B revised to add clarity~~

Revision 20 (10/01/2017):

- ~~Biennial Cover to Cover Review~~
- ~~Updated name of manual from “Generation and Transmission Interconnection Process” to “New Services Request Process”~~
- ~~Section 1 – Labeled image as new Exhibit 1~~
- ~~Section 1.1 - Requirements for Generating Units~~
 - o ~~Provides clarification of Generating Units and participation in the PJM Markets~~
- ~~Section 1.2 – Interconnections with municipalities, co-operatives, or non-PJM member electric distribution companies (EDC)~~
 - o ~~Provides clarification of generator requirements for participation in the wholesale market~~
- ~~Section 1.3 – Interconnection Procedures for FERC Jurisdictional and Non-FERC Jurisdictional Facilities~~
 - o ~~Provides clarification on generators that wish to participate in the Wholesale market, but are connected to an EDC~~
- ~~Section 1.12 – Consent to Assignments~~

- o ~~This is a new section that clarifies transfer of ownership processes before and after commercial operation of a Generator~~
- ~~Section 1.20 – Non-Queue Interconnection Service Agreements~~
 - o ~~This is a new section which provides guidance for existing Generators which require an ISA~~
- ~~Section 1.21 – Serving Load as a Generator~~
 - o ~~Unless allowed under applicable state or local law, an entity is not permitted to serve another entity's load. Station Power loads can be served between generators in a single portfolio.~~
- ~~Section 2.1.2.1 – Site Control~~

- o Provides additional clarification on the requirements for site control
- Section 2.1.2.2 – Generation Interconnection Requests
 - o Multiple requests behind the same Point of Interconnection
 - o Fuel Change
 - o Attachment Y applications
 - o Attachment BB applications
- Section 2.1.4 – New Service Request deficiency reviews
 - o Requires a reasonable on-service date based on Study(ies) timeline and construction schedule
- Table 2-2-1: System Impact Study costs
 - o Corrected tables
- Section 2.3.1 – Queue Priority and final agreement issuance and determination of security requirements for moving out of sequence
 - o Added a discussion regarding cost allocation for network upgrades and the prioritization among queue positions with allocations to a shared network upgrade.
- Section 2.4 – Types of Network and Local Upgrades
 - o Provides clarification for the various types of Network Upgrades
 - o Labeled image as new Exhibit 2
- Section 2.5 – Transfer of Capacity Interconnection Rights
 - o Describes the process for transferring existing CIRs
- Section 2.6 – Work Papers
 - o This section defines Work Papers and how they relate to the RTEP base case used for modelling New Services Requests
- Section 3.1.4 – Expedited and/or Combined Study Analysis
 - o This section provides clarification for the combined study process and how it applies to small Generators
 - o Labeled image as new Exhibit 3
- Section 4.1.2 – Interim ISA vs. ISA with Interim Rights
 - o This section describes the difference between advancing construction with an Interim ISA, and advancing the in-service date of the Generator coming into service ahead of the base case study year.
- Section 4.1.3 – Security Requirements
 - o Provides clarification on the security requirements for an ISA, WMPA, or UCSA
- Section 4.1.4 – Agreement Milestones

- o Provide clarification on the required Agreement Milestones
- o Labeled image as new Exhibit 4
- Section 4.2.1 - Option to Build
 - o Provides clarification on "Option to Build"
- Section 4.3 - Wholesale Market Participation Agreement (WMPA)
 - o Defines what a WMPA is
- Section 5.1 - Behind the Meter Generation Projects
 - o This section provides additional clarification of Behind the Meter Generation (BtMG) interconnections
- Removed reference to Alternate Queue in Sections 1.9 and 3.1.2
- Made changes to language to remove separate procedures for Network Upgrades with costs <\$5 Million in Attachment B, Sections B.2, B.3.1 and B.3.2

Introduction

Welcome to the New Services Request Process Manual. In this Section you will find:

- A table of contents
- An approval page that lists the required approvals and the revision history
- This Introduction
- Sections summarizing the guidelines, requirements and procedures for Generation and Transmission interconnection, including Developer actions and PJM actions.
- Attachments that include additional supporting documents and tables.

About This Manual

This PJM Manual, ***New Services Request Process*** is one of the PJM Manual 14 series family. This manual guides developers of generation and merchant transmission projects through the planning up to the request for facility construction.

Intended Audience

The intended audience for this PJM Manual includes the following:

- Developers of generation and merchant transmission facilities and their staffs interested in locating facilities within PJM.
- Existing Generation Owners planning increases to an existing generating resource.
- PJM Transmission Owners and other PJM Members and their staffs.
- PJM staff.

References

The entire PJM Manual 14 series addresses issues that may be related to or of interest to the Interconnection Customer. The reader of this manual is urged to review the other manuals for additional material of interest. All PJM manuals can be found in the library section on PJM's website. In addition, the reader is urged to also check PJM committee postings for possible draft revisions that may be awaiting posting under the Library/Manuals section of PJM.com.

Section 1: Interconnection Process Overview

Entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit or decommissioning of a generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM’s defined interconnection process. This process ensures the successful, timely completion of PJM’s planning, facility construction and operational and market infrastructure requirements. For the purposes of this Manual, the term “Developer” is used to encompass any entity which bears responsibility for bulk power system upgrades, whether a third party seeking interconnection or an existing Transmission Owner with responsibility for Baseline Upgrades or self-identified enhancements.

Use the following decision tree to determine the appropriate Tariff attachment to complete to submit a New Service Request.

Decision Tree to Determine New Service Request Tariff Attachment

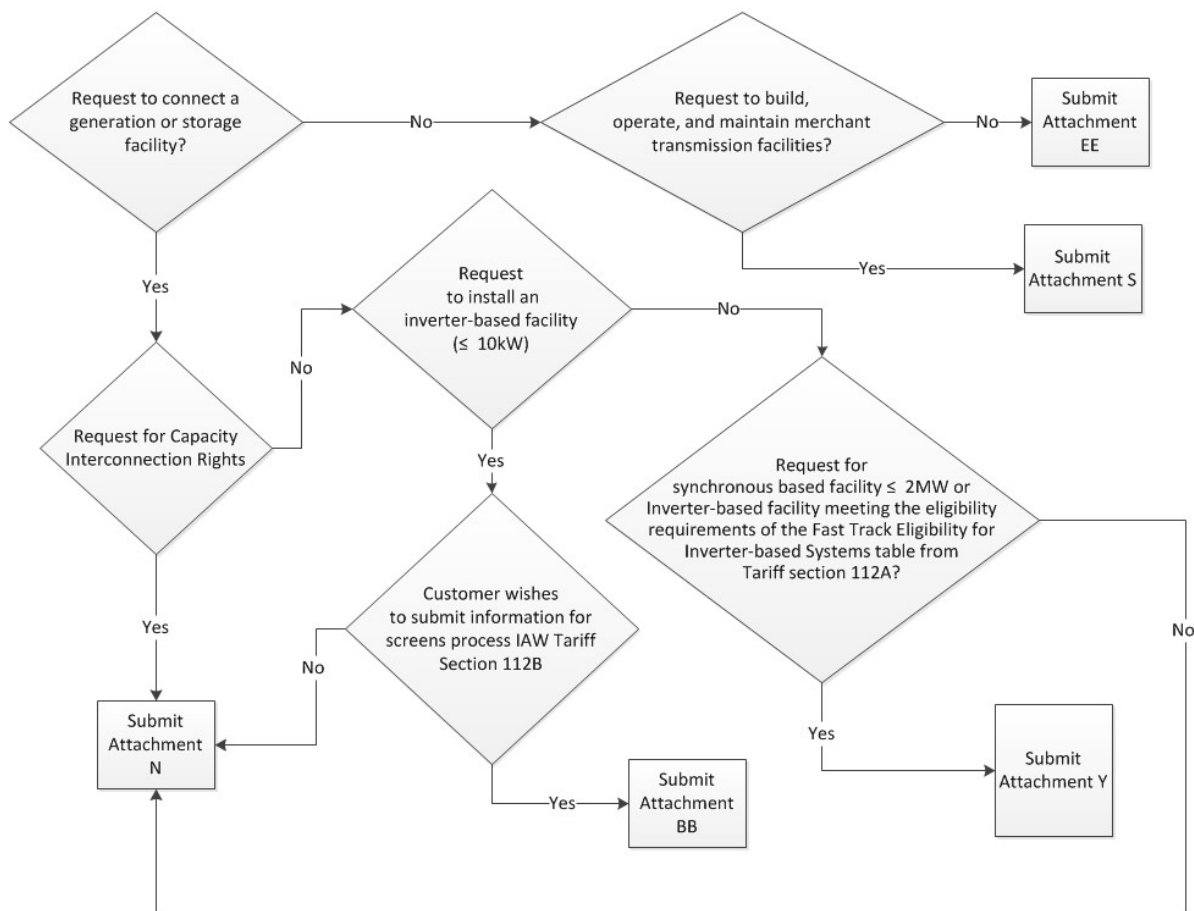


Exhibit 1: Tariff Attachment Decision

PJM Manuals offer a set of guidelines to ensure successful interconnection and operations within PJM.

Manual **Attachment A**– Interconnection Process Flow Diagram - portrays in more detail the pertinent planning steps from the initial New Service Request up to the request for facility construction.

The PJM Manual 14A content is consistent with and elaborates on the terms and conditions found in the source PJM documents. The primary source documents for Manual 14A are the PJM Open Access Transmission Tariff (Tariff) and the PJM Operating Agreement. Other applicable source documents may include the PJM Transmission Owners Agreement and the PJM Reliability Assurance Agreement. The source documents remain the final authoritative documents and these documents control with regard to any inconsistencies between them and the PJM Manuals.

1.1 Requirements for Generating Units

Under the definition of Generation Capacity Resource in the PJM Open Access Transmission Tariff (Tariff) and Reliability Assurance Agreement (RAA), Capacity Interconnection Rights are awarded to a generation unit. While some technologies, such as wind, solar, hydro, and combined cycle facilities may participate in the Capacity Market through the aggregation of multiple generating units (see, for example, the Capacity market participation requirements in PJM Manual 21), PJM must be able to model each machine that can participate as a generator in its planning process. Moreover, in accordance with the PJM Tariff, for any Behind the Meter Generation that desires to be designated, in whole or in part, as a Capacity Resource or Energy Resource, PJM must study and demonstrate that Behind the Meter Generation qualify as such Behind the Meter Generation. To allow PJM to study and demonstrate that Behind the Meter Generation cannot inject power past the Point of Interconnection, generation that contains both: (1) Behind the Meter Generation; and (2) generation interconnected or interconnecting the transmission system or FERC-jurisdictional distribution system in the PJM region must provide PJM with all generation gross capability.

If a generating facility is to be subdivided between separate business entities behind a single Point of Interconnection, each entity shall own its own revenue grade meter or must enter into a commercial agreement, which governs disbursement from a single payment. Regardless, at least one revenue grade meter, to be defined as the meter of record, must be installed at the Point of Interconnection. If individual revenue grade meters are installed in addition to the meter of record, they will provide each participant their percentage of the meter of record. It will be required of the behind the Point of Interconnection parties to submit to PJM hourly MW totals by entity equal to the total of the meter of record.

1.2 Interconnections with municipalities, co-operatives, or non-PJM Transmission Owner member distribution companies

A Generation Owner seeking to be designated, in whole or in part, as a Capacity Resource or Energy Resource, by connecting to any municipality, co-operative, or non-PJM Transmission Owner member distribution company that are not jurisdictional to PJM's Tariff, must work independently with that non-FERC jurisdictional entity to obtain permission to interconnect to and wheel through their system, or to build a dedicated attachment line through the affected system to the PJM System. If a non-FERC jurisdictional entity allows wheeling for wholesale

activity, then it is up to that entity to follow all FERC requirements that wholesale wheeling requires.

Additionally, the Developer must enter the PJM New Services Queue. The Point of Interconnection for requests to non-FERC jurisdictional entities is where the non-FERC jurisdictional entity's system connects to PJM member facilities. PJM will study the generation impacts at the Point of Interconnection for reinforcement to the PJM system. During the same time that PJM is conducting its study, the customer may need to separately enter the necessary non-FERC jurisdictional entity's interconnection queue process in order to obtain a right to connect the new facility to the non-FERC jurisdictional entity's system. PJM will perform necessary studies to identify and mitigate any impacts to the PJM system. Upon completion of PJM studies, PJM will issue a Wholesale Market Participation Agreement (WMPA) with appropriate milestones for the Developer to complete the non-FERC jurisdictional entity's interconnection process, commence construction, and commence commercial operations within reasonable time periods. The WMPA will permit the Developer to participate in PJM's wholesale market after completing the non-FERC jurisdictional entity's interconnection process and commencement of generation transactions.

Failure to timely enter and maintain active queue status the non-FERC jurisdictional entity's interconnection process, if required, will result in withdrawal from the PJM queue. Failure to meet the milestones in the WMPA will result in termination of the WMPA. Failure to participate in the wholesale market after becoming commercial will result in termination of the WMPA.

1.3 Interconnection Procedures for FERC Jurisdictional Facilities and Non-FERC Jurisdictional Facilities

In accordance with the Tariff, a Developer of a generator interconnecting to the in the PJM region to be designated, in whole or in part, as a Capacity Resource or Energy Resource, must enter the generator into the PJM New Services Queue. However, the applicability of the Tariff interconnection process for a wholesale generator interconnecting to distribution facilities varies depending on whether FERC has jurisdiction over the distribution facilities.

The PJM Tariff provides interconnection procedures for generation resources connecting to FERC-jurisdictional facilities. This Section 1.3 applies only to wholesale transactions on non-FERC jurisdictional facilities that are not interconnections to municipal utilities, cooperatives, or non-PJM Transmission Owners member distribution company that are not subject to PJM's Tariff. See Section 1.2 for information regarding interconnections to municipal utilities, cooperatives or non-PJM Transmission Owners' member distribution companies.

If a generation resource that desires to be designated, in whole or in part, as a Capacity Resource or Energy Resource is proposing to interconnect to facilities that are not under FERC's jurisdiction (except those entities described in Section 1.2), PJM must still complete studies to verify no impacts to the PJM system. The generation resource owner will be required to enter the non-FERC jurisdictional entity's interconnection process in parallel to PJM's New Services Queue.

1.4 Merchant Transmission Interconnection Facilities

As specified in the PJM Tariff and Schedule 6 of the PJM Operating Agreement, the Developers of Merchant Transmission Facilities that interconnect with the PJM Transmission System may be entitled, subject to certain restrictions, to elect certain transmission rights that are created by the addition of such facilities. Discussions of these rights and specific design, construction, operational and maintenance aspects of merchant transmission interconnection facilities can be found by referring to the PJM Tariff.

1.5 Initiating the Generation and Transmission Interconnection Planning Process

In order to initiate the Interconnection Planning Process, a Developer must contact PJM through PJM's hotline or through PJM's web site. The Developer must submit a completed Interconnection Request. This is accomplished via the execution of a Feasibility Study Agreement, per Tariff Attachment N, Attachment Y, or Attachment BB for generation interconnection requests and Tariff Attachment S for merchant transmission interconnection requests. All Tariff attachments for application of service in the New Services Queue (interconnection queue) can be found in the library section of PJM's web site. Completed Attachments, including the submittal of all required data, must be accompanied by the appropriate fees as detailed in following sections of this Manual in order to reserve a place in PJM's interconnection New Services Queue.

1.6 Project Management and Client Management

After submitting a PJM New Service Request, PJM assigns a project manager. The project manager will be responsible for working with each Developer and their respective staff to complete the necessary steps related to interconnection planning. Additional project managers will be assigned for subsequent facility construction and operational phases of the project.

After contacting PJM for the first time through PJM's hotline or through PJM's web site, the Developer will be assigned a Client Manager. Client Managers coordinate PJM activities that facilitate each Developer's membership and market participation, bridging any concerns or coordination issues with appropriate PJM staff including the respective PJM project managers who oversee the interconnection process.

1.7 Electing Capacity Resource Status versus Energy Resource Status

A Developer must elect the status type for the generating capability associated with each interconnection request: Capacity Resource Status or Energy Resource Status. A Capacity Resource status designation permits the generator to be utilized by PJM Load Serving Entities to meet capacity obligations under the terms of the PJM Reliability Assurance Agreement (RAA), available in the [Library](#) section of PJM's website.

- **Capacity Resource Status:** Units must meet certain interconnection requirements for being granted this status including requirements for deliverability. Capacity Resource status is granted based on the availability of sufficient transmission capability to ensure the deliverability of generator output to network load and to satisfy the regional reliability

requirements of the NERC region in which the generator is located - ReliabilityFirst or SERC. Specific analytical tests performed during the Generation Interconnection Feasibility Study and System Impact Study reveal the specific transmission system upgrades required to meet these reliability criteria. Capacity Resource Status conveys specific capacity interconnection rights enabling a unit to participate in PJM capacity markets. Through these markets, LSEs may procure capacity rights to meet their respective capacity obligations under the terms of the PJM Reliability Assurance Agreement.

- **Energy Resource Status:** The planning studies for generating units seeking this status do not include the deliverability analyses required of those units seeking Capacity Resource status. As such, Energy Resource units are only permitted to participate in the energy market. Such units do not receive Capacity Interconnection Rights and may not participate in PJM Capacity markets.

1.8 PJM Membership

Membership in PJM is granted under the terms of the PJM Operating Agreement. The Client Manager assigned to each Interconnection Request will guide each Developer through this process. While PJM membership is not required for the initial planning and construction phases of a given generation or merchant transmission interconnection project, Membership will be required prior to commercial operation. And, in many cases, Membership will be required in order to integrate operational and market infrastructure with PJM. PJM Membership entails certain data requirements, operational and market coordination, committee support and financial obligations

1.9 Membership in NERC Regional Councils

PJM operates within the geographic boundaries of several regions of the North American Electric Reliability Corporation (NERC), including applicable areas of the ReliabilityFirst and the SERC Reliability Corporation. Any new signatory to the PJM Operating Agreement is obligated to be in compliance with the respective planning, operating and membership requirements of the respective NERC Council in which their facilities are located.

1.10 The Interconnection Request Studies

The PJM Operating Agreement, Schedule 6, and the Tariff, Parts IV and VI, describe the procedures used to process requests for interconnection with the PJM transmission system. The Operating Agreement and Tariff establish the statutory basis for the business rules, described in detail in this Manual M14A, for the interconnection request process. These business rules include three analytical steps:

1. Feasibility Study
2. System Impact Study
3. Interconnection Facilities Study.

Each step imposes its own financial obligations and establishes milestone responsibilities.

Projects within each time-based queue are evaluated against a baseline benchmark set of studies in order to establish project-specific responsibility for system enhancements, separate from general network upgrades suggested by the results of baseline analyses. Each Developer is encouraged to participate in the activities of the Transmission Expansion Advisory Committee (TEAC) and its Sub regional RTEP Committee. PJM consults with the TEAC and Sub regional RTEP Committees as part of the larger Regional Transmission Planning Process through which a coordinated regional expansion plan – including expansions necessitated by generation and merchant transmission interconnection - is reviewed.

Important PJM interconnection process steps established to implement provisions of the PJM Tariff:

- The interconnection queuing process including the procedures used to initialize the interconnection evaluation process based on the timing of the receipt of all requests
- The cost responsibility for transmission upgrades required for interconnection;
- The rights accorded to a generator after it has satisfied Tariff requirements;
- The required Interconnection Service Agreement (ISA) and Construction Service Agreement (CSA). Each of these two agreements is executed by and among three parties: the Developer, the Transmission Owner and the Transmission Provider (PJM).

1.11 Changes to Existing or Proposed Generation

An existing or proposed generating unit may experience changes which will require consideration under PJM's interconnection, process:

- **New Ownership Requirements:** If a generating facility is acquired by a new owner, then the transfer of responsibilities and rights in the PJM market for the transferred facility will be conveyed to the new owner following notification to PJM by the selling and purchasing entities.
- **Unit Output Increases:** If a Generation Owner plans to increase the Maximum Facility Output (MFO) or the amount of Capacity Interconnection Rights (CIRs) of an existing generating unit or active Interconnection Request in the PJM study queue to a MW value greater than the amount already specified in a generating unit's existing ISA or active Interconnection Request, then that additional MFO or CIRs will be treated as a new generation Interconnection Request subject to the procedures discussed in Manual 14A. If a proposed generating unit increase is less than 20 MW, the Generation Owner may be eligible to follow the Small Generation Interconnection Process, set forth in Part IV, subpart G of the Tariff and discussed herein below. Maximum Facility Output (MFO) and Capacity Interconnection Rights (CIRs) are defined in Part I of the Tariff "Common Service Provisions, under "OATT Definitions".

If a Generation Owner changes the electrical characteristics of the existing generating unit(s) that were previously studied by PJM, but is not increasing the MFO or CIRs, then the Generation Owner must request that a necessary study be performed by PJM (See PJM Manual 14A Section Tariff Section 36.2A.4 and Attachment O, Appendix 2, Section 3.1). Even when not increasing MFO or CIRs, if a Generation Owner wishes to parallel generating units in excess of the number of units previously studied by PJM, this would change the electrical

characteristic and require a necessary study prior to operating with additional generating units. If a Generation Owner installs a spare generating unit with different electrical characteristics than the primary generating unit, the spare generating unit must be studied with a necessary study prior to being paralleled with the system.

1.12 Consent to Assignments

Prior to transferring ownership of a project or company, a Developer, Generation Owner or Transmission Owner must complete an applicable “consent to assignment agreement.” The PJM Law Department has established templates for consent to assignment at the following stages of development and operation:

1.12.1 Assignment prior to the final agreement

Prior to the ISA, WMPA or UCSA being executed, a customer should work with their assigned Interconnection Projects Department project manager to complete the agreements located on pjm.com. Two methods for assignment prior to the final agreement have been developed: 1) a combined buyer / seller agreement or 2) the buyer and seller each separately completing respective agreements.

1.12.2 Assignment after the final agreement and prior to commercial operation

During the construction phase, which commences upon execution of the final agreement(s) and prior to commercial operation, if a Developer or lender elects to assign a project, they need to work with the Infrastructure Coordination Department project manager to complete the agreements located on pjm.com. Three agreements are available for the initiating party: 1) a lender agreement, 2) Interconnection Customer agreements, and 3) Transmission Owner agreements.

1.12.3 Assignment after commercial operation

The following applies to any generation, transmission or transmission owner facility participating in the PJM Market. Generator owners or merchant transmission facility owners that wish to assign their facility to another entity or to perform a lender transfer after commercial operation shall follow the following instructions:

- Notify your intent to your PJM client manager a minimum of 90 days prior to the financial transfer to assure adequate time to make necessary agreement modifications and filings with the Federal Energy Regulatory Commission.
- Identify to PJM all existing underlying affected agreements, such as Power Purchase Agreements, two-party interconnection agreements, PJM Interconnection service agreements; and
- Identify any changes to the facility that have occurred since the current effective agreement was executed that are not currently documented in the existing agreement, such as scope change documents from construction, retirements of units depicted or described in the agreement, modifications to the facility that would be reflected on a one-line diagram.

PJM will review the proposed assignment and existing agreements to determine the proper documentation and filings necessary to effectuate the requested asset transfer or lender change.

1.13 Small Generation Interconnection Considerations (20 MW or less)

Requests for the interconnection of new resources of 20 MW or less, or for increases of 20 MW or less for existing generation may be processed through expedited procedures, in accordance with Part IV, Subpart G of the PJM Tariff. Generating resources of this size fall into one of three categories:

1. Permanent Capacity Additions: units which are expected to remain connected to the transmission system for the life of the resource, expect to receive capacity interconnection rights, and may be utilized to meet the capacity obligations of LSEs.
2. Permanent Energy Resource Additions: units which are expected to remain connected to the transmission system for the life of the resource but receive no Capacity Transmission Interconnection Rights and are not permitted to be used to meet capacity obligations of LSEs.
3. Temporary Energy Resource Additions: units which are only expected to remain connected to the transmission system temporarily (less than six months), participating in spot market activity during peak demand periods and requiring only minimal or no transmission enhancements.

The planning process requirements for each of these are described in more detail in Manual 14B.

1.14 Distributed Generation

Developers who are considering construction of generating facilities within PJM which are 20 MW or less may follow the Small Generator Interconnection process described above.

1.15 Demand Response Resource

If a plant operator seeks operation as part of a load management arrangement, the operator is directed to PJM's load management program, found on PJM's web.

1.16 Behind the Meter Generation

Any Behind the Meter Generation which seeks to be designated in whole or in part as an energy or capacity resource must submit a Generation Interconnection Request for the portion of the unit's output that will participate in the PJM market. Further, sites with 10 MW or more must abide by PJM metering requirements as well as market, operational and settlement requirements. Manual 14D (Appendix A) describes the treatment of Behind the Meter generation, provisions for which are captured in PJM's Tariff, Subpart A, Section 36.1.A.

As with any other Interconnection Request, The Developer will be assigned a Project Manager for each process phase captured in Exhibit 1. The Project Manager will be responsible for working with each Developer and staff to complete the respective steps for that particular phase. Attachment B: Interconnection Process Team Role Clarity Diagram captures Implementation Team roles for each interconnection process phase (including a PJM Project Manager for each phase) and shows how each Manual aligns with each phase.

Generating resources operating “behind the meter,” in isolation from the PJM bulk power transmission system and which do not intend to participate in the PJM wholesale energy market, need only coordinate planning, construction and/or operation with the host Transmission Owner.

1.17 Coordination of studies between PJM and MISO

MISO and PJM shall conduct Interconnection Studies, as necessary, to determine the impacts of Interconnection Requests on each other’s transmission system which will be treated as an affected system. This joint coordination of Interconnection Studies will be in addition to the existing Interconnection Studies that MISO and PJM already perform to evaluate the impacts of their respective queues on their own transmission system.

The Transmission reinforcement and the study criteria used in the coordinated interconnection studies will honor and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and their respective Tariffs.

Example:

- PJM and PJM Transmission Owner study and reinforcement criteria will apply to PJM transmission when PJM evaluates the impact of MISO generation on PJM transmission.
- MISO and MISO transmission owner study and reinforcement criteria will apply to MISO transmission when MISO evaluates the impact of PJM generation on MISO transmission.

1.17.1 Study of PJM Interconnection Request impacts on MISO transmission

During the course of PJM Interconnection studies, PJM shall monitor the MISO transmission system and provide the draft results of the potential impacts to MISO. These potential impacts shall be included in the PJM System Impact study report along with any information regarding the validity of these impacts and possible mitigation received from MISO and the MISO transmission owners.

Following the completion of the PJM Feasibility Study and after the customers execute the PJM System Impact Study Agreement, PJM shall forward to MISO, at a minimum of twice per year (April 15 and October 15), information necessary for MISO and the MISO transmission owners to study the impact of the PJM interconnection request(s) on the MISO transmission.

MISO and the MISO transmission owners shall study the impact of the PJM interconnection request(s) on MISO transmission and provide draft results to PJM by:

- March 1 for PJM interconnection requests provided to MISO on or before October 15 of the previous year,
- September 1 for PJM interconnection requests provided to MISO on or before April 15 of the same year.

These impacts shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcement(s). At times PJM may identify to MISO the need to perform studies associated with an interconnection request other than the times identified above. MISO shall endeavor to study these requests at

the earliest time which is feasible, but not later than the times as specified above (commencing after April 15 and October 15).

In the event of project withdrawals in the PJM queue, MISO may perform additional reliability analysis during the Facilities Studies phase and revise the affected system study results provided during the PJM System Impact Study phase. If MISO identifies required Network Upgrades, on the MISO transmission system, due a PJM interconnection request, then the PJM Interconnection Customer(s) shall be required to follow all provisions, delineated under Attachment X of the MISO tariff, related to Facility Study funding and appropriate Network Upgrade Facility Construction Agreement.

Cost allocation for required Network Upgrades on the MISO transmission, for PJM interconnection requests, shall be governed by and subject to MISO Tariff and Manuals.

MISO shall determine the curtailment necessary associated with the request for service (e.g.: transmission service, generation interconnection, etc.) which was identified as impacting a MISO constraint.

1.17.1.1 Use of system reinforcements outside of MISO for MISO constraints

During the determination of reinforcements, required for MISO constraint mitigation, PJM and MISO may identify other planned non-MISO reinforcement(s) that may alleviate a constraint inside of MISO's boundaries. Under such circumstances any PJM project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are put in place. MISO shall determine the necessary injection limits, associated with the PJM New Service Request, that will be implemented in Real Time until the necessary upgrades identified through MISO's affected system analysis are in-service.

1.17.2 Study of MISO Interconnection Request impact on PJM Transmission

During the course of MISO Interconnection studies, MISO shall monitor the PJM transmission system and provide the draft results of the potential impacts to PJM. These potential impacts shall be included in the MISO System Impact study report along with any information regarding the validity of these impacts and possible mitigation received from PJM and the PJM transmission owners.

Prior to commencing the MISO DPP study MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), information necessary for PJM and the PJM Transmission Owners to study the impact of the MISO interconnection requests on the PJM territory. For the prescribed times when MISO provides this information to PJM, January 1 and July 1, PJM and the PJM Transmission Owners shall study the impact of the MISO interconnection requests and provide draft results on the PJM transmission by

- March 31, for requests submitted to PJM on or before January 7th of the same year, and
- September 29 for requests submitted to PJM on or before July 7th of the same year.

These impacts shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcement(s). At times MISO may identify to PJM the need to perform studies associated with an interconnection request other than the times identified above. PJM shall endeavor to study these requests at the earliest time which is feasible, but not later than the times as specified above (commencing after January 7 and July 7).

If PJM identifies required Network Upgrades, on the PJM transmission system, due a MISO interconnection request, then the MISO Interconnection Customer(s) shall be required to follow all provisions, delineated under Tariff, related to Facility Study funding and appropriate Network Upgrade Facility Construction Agreement obligations.

Cost allocation for required Network Upgrades on the PJM transmission, for MISO Interconnection projects, shall be governed by and subject to Tariff and Manuals.

PJM shall determine the curtailment necessary associated with the request for service (e.g.: transmission service, generation interconnection, etc.) which was identified as impacting a PJM constraint.

1.17.2.1 Use of system reinforcements outside of PJM for PJM constraints

During the determination of reinforcements, required for PJM constraint mitigation, PJM and MISO may identify other planned non-PJM reinforcement(s) that may alleviate a constraint inside of PJM's boundaries. Under such circumstances, any MISO project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are put in place. PJM shall determine the necessary injection limits, associated with the MISO Interconnection Request, that will be implemented in Real Time until the necessary upgrades identified through PJM's affected system analysis are in-service.

1.17.3 Study of PJM Transmission Service Request impacts on MISO transmission

MISO and PJM shall coordinate on new Transmission Service Request (TSR) Studies to determine impacts on each other's transmission system which will be treated as an affected system. The coordination and completion of these studies will follow the same basic procedures described in Section 1.12.1 above relating to interconnection request studies.

1.18 Studies for Long Term Firm Transmission Service

Transmission Service Requests are received through the PJM OASIS and, in the case of Long Term Firm Transmission Service, must be evaluated along with the other requests for service which are studied in the PJM New Services Queue when those requests for Long Term Firm Transmission Service are requests outside of the Available Transfer Capability, ("ATC"), horizon of 18 months. The ATC horizon extends for 18 months from the date of the Oasis request.

Additional details regarding the ATC horizon are located in PJM Manual 2: Transmission Service Request.

The first step in the evaluation of Long Term Firm Transmission Service associated with the inclusion of the request in the New Services Queue is during the to perform a Initial Study Feasibility Study. During the conduct of the Initial Studies of requests for transmission service as outlined in PJM Manual 2 Feasibility Study, PJM will conduct a screening of the requested service under conditions similar to the performance of with the remaining New Service Requests in the Feasibility Studies discussed later in this manual for generation and transmission requests, however, the results of these Initial Studies of transmission service shall only provide a listing of the possible impacted elements and not address the costs or time to complete any reinforcements.

If the customer proceeds forward after the Initial Feasibility Study and they must execute the System Impact Study Agreement, PJM shall conduct a study of the requested service following the close of the New Services Queue in which the request for service is



~~contained which shall~~

be similar to with the remaining New Service Requests in the System Impact Study. This will occur during the time that the remaining New Service Requests are being evaluated for the Feasibility Study and will be performed with all New Service Requests in the case for the study as if those projects had proceeded forward to the System Impact Study phase however the commercial probability for the other New Service Requests shall remain at the value specified for the Feasibility Study. This study will provide the transmission service customers additional information in order to determine if they will move forward by defining the costs associated with reinforcements which may be required to grant the requested service. Following the completion of this study, the transmission service customer will receive a System Impact Study and will be required to move forward into the Facilities Study phase based on the results of this study.

The requests for transmission service will again be evaluated during the Tariff specified time period for the System Impact Study associated with the New Services Queue the customer is in. The results of this study will be used to modify and revise the requirements as previously specified in the original System Impact Study and the Facilities Study will be adjusted appropriately.

1.19 Interim Deliverability Studies

PJM's process for the conduct of studies associated with projects which have requested service or evaluation in the New Services Queue, or projects which are under study considering PJM as an Affected System, require that all studies be performed on a case for each study which is independent of the requested service dates associated with the proposed project/service. The use of the same case for one projects evaluation, which is consistent with the same case as the case used for other projects under study, allows for development of required upgrades while preserving the rights associated with the individual Queue Position for the project(s) under study in that queue study. As a result of the use of a case which may not coincide with the requested year of service for any individual project, the ability of any individual project to come into service in a year before the year of the case used for the study of the project is dependent on the availability of system capability in any earlier year as can be determined during interim deliverability studies.

Projects which rely on reinforcements which have not been constructed at the time the project comes into service will also require evaluation on a case which is needed to determine the capability of the existing system to allow the projects output or flow to be granted through the conduct of interim deliverability studies.

- Example: A project was evaluated and it was found to require construction of a network reinforcement which has not been constructed when the project desires to come into service. An interim deliverability study will be conducted to determine what output, or flow, can be accommodated on the system prior to completion of the required upgrade.

Interim Deliverability studies will be conducted on a periodic basis, and as required, in support of RPM auctions and preparation of documents for service (e.g.: Interconnection Service Agreement, Upgrade Construction Service Agreement, Interconnection Agreements in areas outside of PJM, etc.). These studies will be conducted to evaluate the available system capability based on when a project requesting service executes the applicable service agreement as well as the projects Queue Position. For projects outside of PJM, the Queue Position is determined based on the timing of the studies for that project and when they are

identified to PJM by the external entity which is responsible for the study of that projects requested service (e.g.: MISO, NYISO, etc.). The availability of service will be determined during interim deliverability studies which shall provide the customer(s) with the availability of service on an annual basis from June 1 of the first year to May 31 of the following year, the planning year (e.g.: 2016 interim deliverability study is applicable to the time period of June 1, 2016 to May 31, 2017). Interim deliverability studies will use the same criteria as is used for the evaluation of the need for reinforcements associated with a project under study.

Interim deliverability studies will incorporate those projects which are anticipated to be in service during the year under study and inclusion of projects in these studies will be based on requests by customers as well as information PJM may have as to those projects which will be in service.

1.19.1 Interim Deliverability Studies associated with projects using reinforcements outside of PJM for PJM constraints

Similar to the requirements as outlined in 1.14 above, the projects evaluated for impacts on PJM facilities which use reinforcements completed on system outside of PJM to alleviate constraints in PJM must have interim deliverability studies conducted.

In circumstances when a project is waiting for the completion of a reinforcement for which they are not responsible for funding, they will receive lower priority for system capability, in relation to the constraint which will be relieved by the reinforcement when it is built, in comparison to those project(s) which are not waiting for the completion of an upgrade associated with that same constraint but have instead proceeded to building a reinforcement.

- Example: Project 1 is identified as impacting a constraint and intends to wait for completion of a system reinforcement they are not funding. Project 2 does not wait for completion of a system reinforcement but instead builds another reinforcement which can be put into service. In this case, regardless of the original position of the two projects in relation to each other, Project 2 will receive higher priority as compared to Project 1 in determining the availability of the current systems capability to allow the project to operate or flow energy while awaiting the completion of the reinforcement under construction and being funded by Project 2.

1.19.2 Affected system studies for PJM New Service Requests

PJM New Service Requests which intend to come into service prior to the completion of any required upgrades associated with affected system constraints or in years prior to the year of the case used in their studies will be subject to limitations based on PJM studies for interim deliverability as well as any limitations which result from affected system¹ studies.

PJM Generation Interconnection Projects that come into service prior to completion of required Network Upgrades associated with constraints on the MISO transmission system will be subject to the MISO Quarterly Operating Limit process, as outlined in the MISO Tariff in Attachment X Section 11.5 and in the MISO Transmission Access Planning Provisional Interconnection Agreement Limit Methodology whitepaper, until required Network Upgrades associated with constraints on the MISO transmission system have been completed. MISO will coordinate project output limitations with PJM on a quarterly basis, and MISO will provide PJM the list of conditions that will be added to PJM Interconnection Customer's Interconnection Service Agreement.

¹ Refer to the Tariff definition for "affected systems".

1.20 Non-Queue Interconnection Service Agreements

PJM's New Services Request process for generation interconnection applies to all new generation and updates to existing generators. For existing generators already interconnected to PJM that are currently operating under a two-party Interconnection Agreement and / or a power purchase agreement, or both, and seek to convert to a PJM three-party ISA due to a transfer of ownership or the power purchase agreement is reaching term, a New Service Request is not required. For purposes of tracking the project identifying the generator in PJM's processes and in FERC filings, and ensuring all costs associated with the conversion are paid by the Generation Owner, PJM developed an agreement and procedures to accomplish the request, referred to as the "Non-Queue Process."

1. In general, a two-party interconnection agreement or power purchase agreement will likely be converted directly to a Tariff Interconnection Service Agreement. However, it is possible that an interconnection arrangement historically permitted may have provisions unacceptable under the Tariff. The following are examples:
 - a generator's attachment facilities arrangement does not conform to PJM's Tariff and requires rearrangement of the Attachment Facilities; or
 - existing metering does not meet PJM requirements, metering modifications may be required.

The list above is not exhaustive nor do the examples portray all potential scenarios and issues that may need to be addressed during the non-queue process; rather, it demonstrates that in addition to drafting an Interconnection Service Agreement, a Construction Service Agreement may be required. PJM has developed a Cost Responsibility Agreement to cover PJM and Transmission Owner costs associated with the agreement(s) development. A deposit of \$10,000 is required with the agreement and any unspent money associated with the deposit are refundable once the agreements are executed or if the customer changes their mind regarding receiving an agreement. The cost agreement must be filed with the FERC. If modifications requiring Transmission Owner construction are required, an associated Interconnection Construction Service Agreement may be required.

Execution of the Interconnection Service Agreement under this process follows the same procedures identified in section 212 of the Tariff. The generator owner will have the same timing requirements to execute necessary agreements as identified in this section of the Tariff. If construction is required by the Transmission Owner, associated Security and requirements identified in the agreement will also apply. Upon execution, PJM will file the agreement(s) with or, if conforming, report them to the FERC. Attorney review and filing durations must be considered by the Generation Owner when requesting PJM to implement these three-party agreements. If the legacy agreements contain terms and conditions not normally captured by the ISA, time for negotiations may also be required. Because of this potential, PJM requests a minimum of a six month notice prior to the termination of a Power Purchase Agreement or an ownership change, which requires conversion to a three-party ISA. Generators seeking a Non-Queue ISA should contact PJM Customer Service. Customer Service contact information can be found on the PJM Web Page under the "Contact Us" link.

1.21 Serving Load as a Generator

Unless allowed under applicable state or local law, an entity is not permitted to serve another entity's load. Station Power loads can be served between generators in a single portfolio.

Section 2: Generation and Transmission Interconnection Planning Process

In this section you will find an overview of the generator and transmission interconnection planning process.

- A description of the Feasibility Study Agreement execution and analysis (see “Generation and Transmission Interconnection Feasibility Study Agreement Execution and Analysis”).
- A description of the System Impact Study Agreement execution and analysis (see “System Impact Study Agreement Execution and Analysis”).
- A description of the Facilities Study Agreement execution and analysis (see “Generation and Transmission Interconnection Facilities Study Agreement Execution and Analysis”).
- Specific requirements for interconnection of large generation and transmission projects with a capability greater than 20MW

2.1 Generation or Transmission Interconnection Feasibility Study Agreement Execution and Analysis

2.1.1 Purpose of the Generation or Transmission Interconnection Feasibility Study Agreement

As a FERC accepted Regional Transmission Organization (RTO), PJM administers the process for the interconnection of all new generators and new transmission facilities to the PJM Transmission Grid. New generation Developers may request either of two forms of interconnection service, Capacity Resource or Energy Resource service. Capacity Resource interconnections receive the right to schedule both Capacity and energy deliveries at a Point of Interconnection – Energy Resource interconnections receive the right to schedule only energy deliveries at a specified point on the PJM Transmission System. Capacity allows the generator to be utilized by PJM load-serving entities to meet Capacity obligations imposed under the Reliability Assurance Agreement. Capacity resources may participate in PJM Capacity Credit markets and in Ancillary Service Markets. Energy Resource status allows the generator to participate in energy markets based on locational prices.

Capacity Resource status is based on providing sufficient transmission capability to ensure deliverability of generator output to aggregate network load and to satisfy various contingency criteria established by the particular regional reliability council (e.g. ReliabilityFirst or SERC) in which the generator is located. See PJM Manual 14B, Attachment C for details of the PJM Deliverability Testing Methods. Specific tests performed during the Generation Interconnection Feasibility Study and later System Impact Study will identify those upgrades required to satisfy the contingency criteria applicable at the generator’s location.

2.1.2 Interconnection Requests and PJM Queue Position

There are two New Service Queue windows per year according to the PJM Tariff **for PJM to accept New Service Requests**. Each window is open for six months: the first queue window closes on April 30th of the calendar year, and the second queue window closes on October 31st of the same calendar year.

Note:

Effective November 1, 2016, PJM will run a transitional, five-month queue. This transitional queue will terminate on March 31, 2017.

All subsequent New Service Queue windows following this transitional period will return to six month durations closing on March 31st and September 30th respectively.

The queue fee structure was designed to incentivize early queue submittals. Earlier queue submittals provide time for data reviews, scoping meetings, planning model development and analysis of all valid New Service Requests.

A New Service Request will not be assigned a queue position until all Tariff requisite information, data, agreements, and deposits are submitted. A New Service Request that does not contain all the required elements is deemed an insufficient request. When submitting an Attachment N, a Generation Interconnection Customer must certify that it has provided all information.

Upon receipt of an executed New Service Request and the required deposit, PJM will open a chargeable account and begin reviewing the New Service Request submittal. Whether the request is insufficient, lacking required elements, or deficient, provided all required elements but with incorrect, missing or underprovided elements, PJM will commence a review of the submittal. The costs associated with the time required to review the submittal will be deducted from the deposit.

Note:

Effective November 1, 2016, PJM will perform a deficiency review as long as a Developer provides all information other than site control. While PJM will perform the deficiency review, the project will not be assigned a queue position until site control is received. The customer must provide site control by the earlier of the end of the deficiency period or the close of the queue window. Providing site control after a deficiency window has already started does not establish new deficiency window period. Site control must be cleared within the original deficiency window period.

2.1.2.1 Site Control

The Tariff states that a Developer must show evidence of site control; and site control is required for a project to have a valid queue position. The Tariff also provides PJM the authority to verify site control that is fully sufficient for the technology and MWs requested for a proposed generating facility. PJM ensures that Generation Interconnection Customers proposing facilities have adequate land to support the proposed generation facilities required to preserve the PJM system rights (MW Energy and MW Capacity) they seek to obtain through their queue request. Accepting a New Service Request for more MW capability than the site and/or proposed technology is capable of producing harms subsequently queued New Service Customers by reducing available system capability. PJM requires site control to be in the name of the party identified on the interconnection request or the parties must demonstrate to PJM's satisfaction the relationship between the owner with site control and the party requesting interconnection. The same requirement applies to Transmission Interconnection Requests initiated with Attachment S at the System Impact Study phase. Although there is some flexibility as to what documents may be submitted to support site control requirements, site control evidence for the interconnection process typically demonstrates three key elements: conveyance, term, and exclusivity.

- Conveyance is demonstrated through a document retained by the Interconnection Customer that conveys the property to the Interconnection Customer (i.e. deed or lease) or guarantees the Interconnection Customer the right to future conveyance at Interconnection Customer's sole discretion (i.e. option to lease or option to buy).
A Memorandum of Understanding (MOU) or a Letter of Intent (LOI) to demonstrate conveyance is not sufficient since MOUs/LOIs do not contain firm and sole site control commitment or exclusivity, from the property owner to the Interconnection Customer.
- Term, the minimum duration required to evidence site control is based upon the anticipated duration of the study process for the relevant project, i.e., three years for large generation projects and two years for small generation projects. The durational requirement is directly tied to the expected time required to complete the Interconnection Process.
- Exclusivity is evidenced by written acknowledgement from the property owner of the identified site that, for the term (which shall be, at a minimum, equal to the duration requirement) of the lease or option agreement, the property owner cannot make the identified site property available for purchase or lease to anyone other than the Interconnection Customer.

The evidence of ownership provided for site control must be from the same company name that is providing the New Service Request or the parties must demonstrate to PJM's satisfaction the relationship between the owner with site control and the party requesting interconnection. The New Service Request agreement is between a specific customer and PJM and all documentation supporting the agreement must be in the same name as the customer identified in the New Service Request agreement. FERC Order 807 allows multiple projects to interconnect behind a Point of Interconnection. A shared facilities agreement is required if jointly owned common Attachment Facilities are proposed.

The Generation Interconnection Customer's site plan submitted with the Attachment N application must show the arrangement of the proposed facilities for the amount of MW requested. This is needed for all types of generation. In the case of solar generation, the determination of sufficient land to accommodate the proposed installation is an engineering analysis based on the capability of solar panels proposed, the solar panel arrangement, and the geographical site location. Similarly, land needed for a wind generation installation is also calculated based on the size and location of the wind turbine.

If PJM receives an interconnection request that does not provide a site plan of the proposed facilities along with accompanying information to determine adequate land space, the request will be deemed deficient by PJM. For example, an interconnection request received for a 25 MW solar installation on one acre of land is deficient because it is not technically feasible to produce that much output with that amount of land. In this case, PJM will ask that the customer provide evidence of the additional site control necessary to accommodate the full level of power output requested or require the customer to reduce the proposed output to match the site area. In the event of a disagreement between PJM and the Interconnection Customer, PJM will accept, a Professional Engineer (PE) stamped site plan drawing (licensed in the state of the facility location) that depicts the proposed generation arrangement and specified the Maximum Facility Output for that arrangement. Failure to take one of these measures will result in the queue request being terminated and withdrawn.

2.1.2.2 Generation Interconnection Requests

Multiple requests behind the same Point of Interconnection

PJM performs all studies at the Point of Interconnection (POI). Subdividing projects into separate projects behind the same POI does not avoid cost allocation requirements nor does it eliminate material impact review requirements based on the total MW being proposed at the POI.

If multiple queue requests are made behind a single POI, as long as they are made within the same queue, will be studied at the queue position of the latest queue request associated with the facility(ies) being proposed.

PJM understands Tariff rules may require an additional queue request to correct increases to Maximum Facility Output if the initial submittal was in error. As long as the total output at the POI does not exceed the applicable criteria for Tariff Part IV, Subpart G, PJM will treat the combined requests as a single submittal at the later queue position under the small generation process. If the combined MW output from the two requests exceeds the applicable criteria for Tariff Part IV, Subpart G, PJM will study the total output at the later queue position under the large generation process.

If multiple projects are behind the same POI, as indicated above, the cost responsibility will be determined based on the maximum combined power injected at the POI. Additionally, if one of multiple projects withdraws from the queue, the materiality requirements based on the withdrawal will apply to the remaining projects behind the POI. If material, the other queue positions will slide to the next queue.

Fuel Change

An Interconnection Request is for a specific project and includes the fuel type specified by the requestor on the interconnection request agreement. A change of fuel type for all or a portion of an existing interconnection request will require the Developer to submit a new interconnection request. For example, if a Developer would like to convert 20 MWs of a 100 MW solar facility to battery storage, then the first queue position for the solar project must be reduced by 20 MW and a new 20 MW interconnection request for the battery storage must be submitted. The rules for multiple queue requests behind the same Point of Interconnection apply.

2.1.2.2.1 Requests Requiring Attachment N

As determined by Exhibit 1 of this manual, a New Service Request that is required to submit Attachment N shall include at a minimum the information listed below:

- A description of the project location including street address and global positioning coordinates
- A map depicting the property boundaries and the proposed generation facilities' location(s)
- The generator's capability (Maximum Facility Output in MW and, if desired, the amount of MW to be evaluated as a Capacity Resource)
- Fuel type(s) (e.g. natural gas, wind, solar etc.)
- One line diagram showing proposed equipment configuration
- Data as required to complete (refer to Attachment F of this manual)
- Proof of right to control the site for the proposed project

- Anticipated in-service date

Note:

The in-service date must be no more than 7 years from the date the Interconnection Request is received by the Transmission Provider, unless it is demonstrated that engineering, permitting or construction of the project will exceed this period.

- The deposit based on the maximum of either the Capacity or Energy values requested. Deposit amounts are discussed in section 2.1.3 of this manual.

2.1.2.2.2 Requests Requiring Attachment Y

As determined by Exhibit 1 of this manual, a New Service Request that is required to submit an Attachment Y Form of Screens Process Interconnection Request which shall include at a minimum the information listed below:

- Interconnection Customer Information
- A description of the project location including street address and global positioning coordinates
- The generator's capability
- Proof of Certification of the generator and the generator's components
- Fuel type(s) (e.g. natural gas, wind, solar etc.)
- Anticipated in-service date
- Energy Resource Information as required in Attachment Y
- Energy Resource Characteristic Data (for inverter-based machines) as required in Attachment Y
- Deposit. Deposit amounts are shown in Table 3-2: Small Generation Interconnection Process deposit requirements (Interconnection Requests of 2MW or less) and Table 3-1: Small Generation Interconnection Process deposit requirements (Interconnection requests of 2 – 20MW)
- Site control per Attachment Y, section 8
- Diagrams as required per Attachment Y, section 8.

Attachment Y applications are only applicable to a FERC jurisdictional interconnection (refer to section 1.2). If an Attachment Y is received for an interconnection that is determined to be non-FERC jurisdictional, the Tariff processes cannot be used for interconnecting the proposed facilities, and the Tariff screens process does not apply. For non-jurisdictional requests, PJM will study for impacts to the Transmission System and issue a wholesale market participation agreement. It is up to the customer to meet the non-FERC entity's interconnection requirements.

For FERC jurisdictional requests, in order to be accepted and processed as an Attachment Y under the Tariff screens process, the proposed generation must meet the applicable Tariff output requirements and meet the certification requirements of Attachments Z and AA of the Tariff.

The Generation Interconnection Customer must provide an adequate one-line diagram and site plan for their generation facility. Demonstration of site control per Manual 14A Section 2.1.2.1 is also required in order to be considered a valid interconnection request.

Note:

Small Generation Interconnection Queue Submittal Requests submitted under Attachment Y are evaluated using a screens process as referenced in section 3.1.2 of this manual

2.1.2.2.3 Requests Requiring Attachment BB

As determined by Exhibit 1 of this manual, a New Service Request that is required to submit Attachment BB, Form of Interconnection Service Agreement for Certified Inverter-Based Generating Facility, shall include at a minimum the information listed below:

- Interconnection Customer Information
- A description of the project location including street address or global positioning coordinates
- The generator's capability
- Proof of Certification of the generator and the generator's components
- Fuel type(s) (e.g. natural gas, wind, solar etc.)
- Anticipated in-service date
- Small Inverter Facility Information
- Fees. There is a non-refundable processing fee of \$500
- Site control documentation

Attachment BB applications are only applicable to a FERC jurisdictional interconnection (refer to Section 1.2). If an Attachment BB is received for an interconnection that is determined to be non-FERC jurisdictional, the Tariff processes cannot be used for interconnecting the proposed facilities, and the Tariff screens process does not apply. For non-jurisdictional requests, PJM will study for impacts to the Transmission System and issue a wholesale market participation agreement. It is up to the customer to meet the non-FERC entity's interconnection requirements.

For FERC jurisdictional requests, in order to be accepted and processed as an Attachment BB under the Tariff screens process, the proposed generation must meet the applicable Tariff output requirements and meet the certification requirements of Attachments Z and AA of the Tariff.

The Generation Interconnection Customer must provide an adequate one line diagram and site plan for their generation facility. Demonstration of site control per Manual 14A Section 2.1.2.1 is also required in order to be considered a valid interconnection request.

2.1.2.3 Merchant Transmission Facilities Requests – Attachment S

Developers requesting to build, own, and operate Merchant Transmission Facilities interconnected to the PJM system must complete Attachment S.

2.1.2.3.1 Upgrade Requests – Attachment EE

2.1.2.3.2 Transmission Interconnection Customers

Developers that seek to request increased capability of existing Transmission Owner facilities or seek to accelerate a PJM board approved RTEP upgrade must complete Attachment EE.

2.1.2.3.3 Upgrade Customers

Developers that seek Incremental Auction Revenue Rights per Tariff Attachment K, Appendix Section 7.8 must submit Attachment EE.

2.1.3 Generation and Transmission Interconnection Feasibility Study Cost Responsibility

As specified in Part IV, Subparts A and G of the Tariff, a party wishing to connect a new generation resource or a new transmission facility to the PJM system must submit an Interconnection Request in the form of an executed Generation or Transmission Interconnection Feasibility Study Agreement (**Tariff at Part VI, Attachment N or Attachment S, respectively**) and a study deposit as specified in the table below (Table 2-1-1). The amount of the deposit is specified in accordance with the size, in MW, as well as the timing of receipt of the Interconnection Request. Refer to Section 3 of this Manual 14A for further details regarding the interconnection process for small resources of 20 MW or less.

PJM will hold 10% of every deposit as non-refundable. The non-refundable portion is held to offset restudy costs associated with a Developers decision to withdraw a project from the queue. If an Interconnection Customer does not withdraw its project, the non-refundable deposit will become refundable after commencement of commercial operations. 90% of the deposit is used to fund the Interconnection Request processing, deficiency review, study costs. If the cost of the Generation or Transmission Interconnection Feasibility study is reasonably foreseen to exceed the standard deposit listed below for the Interconnection Request before the study begins, PJM will require the Developer to pay the additional deposit (see Table 2-1-2 below for expected additional costs by Transmission Owner zone). The additional deposit will be added towards the refundable portion. The refundable portion shall be transferable to subsequent studies or construction phases associated with the individual Interconnection Request. The Developer is obligated to pay the actual costs of studies conducted by PJM on its behalf.

Table 2-1-1: Large New Services Request Process deposit requirements

Month of New Services Queue	Deposit Requirement		Portion held as non-refundable	Maximum deposit
	fixed deposit	Per MW portion of deposit		
1 st - 4 th	\$10,000	\$100	10%	\$110,000
5 th	\$20,000	\$150	10%	\$120,000
6 th	\$30,000	\$200	10%	\$130,000

Note:

The per MW value is the maximum of the Capacity or Maximum Facility Output requested.

If a Developer submits an Attachment N or S in any of the zones listed above, if the standard Tariff deposit is less than the amount shown in the table, the Developer shall provide PJM the difference between the value in Table 2-1-2 below and the standard Tariff deposit. If a Transmission Owner zone is not on the table, then PJM expects the standard Tariff deposit will

cover the Feasibility Study costs. Note however, that a Developer is responsible for actual costs of the study and actual costs may exceed the expected amount.

Table 2-1-2: Large New Services Request Process expected costs

Transmission Owner Zone	Expected Costs
AEP	26K
BGE	15K
ComEd	15K
Dayton	13K
Dominion	12K
Duquesne	19K
FirstEnergy	23K
AEC/DPL/Peppo	12K
PPL	20K
PSEG	17K

The remaining refundable portion of a deposit shall be transferable to subsequent studies associated with the individual Interconnection Request or refunded to the Developer. See below for an example of the cost for an Interconnection Request.

Example:

An Interconnection Customer submits a request for interconnection of a 40 MW facility during the first month of the queue period. The Feasibility Study deposit, example cost, and available money to refund or transfer would be as follows:

- Fixed deposit: \$10,000
- Per MW deposit: \$4,000
- Total deposit: \$14,000 (To be submitted as a single payment)
- 10% portion held as non-refundable deposit: \$1,400
- Refundable portion: \$12,600
- Actual Deficiency Review and Study costs: \$5,451
- Amount available for refund or transfer to subsequent study: \$7,149

2.1.4 New Service Request deficiency reviews

As identified in section 2.1.2, a Queue Position is assigned once all the requisite information and deposit is provided to PJM. Assignment of the Queue Position assures the Developer queue priority, but does not mean that the request is valid.

Interconnection Request validity is determined by a deficiency review. If the Interconnection Request is missing information, is deficient, or if the Developer owes money from prior New Service Requests, PJM will issue a deficiency notification to the Developer within five business days from receipt of the initial Interconnection Request. In addition to site control, data, and deposits, PJM will consider the reasonableness of the planned in-service date stated in the Attachment N request. Any request for in-service in advance of the Tariff prescribed study period is unreasonable. For any generation interconnection request, the in-service date must be after the Tariff due date for the System Impact Study report plus the credible construction schedule. Note that proposed in-service will be modified during the study phase as required to accommodate network upgrades. Upon PJM issuing the deficiency notification, the Developer has 10 business days to provide the missing/ deficient information and/or money. If any required information, including site control, required for a Queue Position to be assigned is missing from the initial Interconnection Request submittal, a Queue Position will not be assigned until that information is received.

An Interconnection Customer must be assigned a Queue Position and have the Interconnection Request determined to be valid prior to the close of the relevant New Services Queue. Any Queue Position that is deficient after the close of the relevant New Services Queue shall be terminated and withdrawn. **To ensure a project has the maximum amount of time to cure deficiencies, Developers must submit their Interconnection Requests prior to the 15th business day prior to the end of the 6th month of the queue window. Any Interconnection Request received after the 5th business day prior to the end of the 6th month of the queue window will inherently have no deficiency cure period capability available, and therefore shall be automatically terminated and withdrawn if it is found by PJM to be deficient.**

The Transmission Provider is afforded an additional five (5) business days to review each Interconnection Customer's deficiency notification response. Any Queue Position for which an Interconnection Customer has not cleared the deficiencies before the close of the relevant New Services Queue will be deemed terminated and withdrawn, even if the deficiency response period for such Queue Position does not expire until after the close of the relevant New Services Queue. If Interconnection Customer's deficiency response is due on the last day of the queue window and the Interconnection Customer timely submits its deficiency response, PJM will engage in its additional 5 business day review of such deficiency response. If PJM identifies remaining unsatisfied deficiencies, the Interconnection Request shall be terminated and withdrawn.

The following is provided to illustrate how the Transmission Provider's additional five (5) business day review period may run concurrently with the Interconnection Customer's ten (10) business day deficiency response period:

If the Interconnection Customer responds to the deficiency notice on the third business day of the Interconnection Customer's deficiency response period, the Transmission Provider's additional five (5) business day review period will run in conjunction with the Interconnection Customers overall ten business day response period. In this example, if on the fifth business day of the Transmission Provider's additional review period (which would also be the eighth day of the Interconnection Customer's deficiency response period) the Transmission Provider identifies remaining, unsatisfied deficiencies in the Generation Interconnection Request, the Interconnection Customer would have two remaining business days to clear such deficiencies before the Interconnection Customer's deficiency response period expired.

However, if, for example, the Interconnection Customer responds to the deficiency notice on the eighth business day of the Interconnection Customer's deficiency response period, the

Transmission Provider's additional five (5) business day review period will run in conjunction with the Interconnection Customers overall ten business day response period. In this example, if on the fifth business day of the Transmission Provider's additional review period (which would be three business days after the Interconnection Customer's deficiency response period expired) the Transmission Provider identifies remaining, unsatisfied deficiencies in the Generation Interconnection Request, the Generation Interconnection Request would be deemed to be terminated and withdrawn since the Interconnection Customer would not be able to cure such deficiencies before the Interconnection Customer's deficiency response period expired.

2.1.5 Changes to Existing Generators and Transmission Facilities

Transfer of ownership of existing generating units and transmission facilities is not subject to the interconnection queuing process unless pre-existing capacity interconnection rights for the unit are not transferred with the change in ownership.

Owners of existing generating plants that plan increases in a plant's output capability above that specified in the generating plant's existing ISA must follow the same procedure as new generation specified in the Tariff and the PJM Manuals. These projects will be placed into the interconnection queue and will be evaluated under the same study procedure as new generation.

Some changes, such as improvements to same-site units injecting at a common point, may be aggregated or combined. Such requests are determined on a case-by-case basis.

Owners of existing generating plants that plan to retire or reduce the plant's output capability must notify PJM in order to address capacity credit issues and any potential PJM System economic and/or reliability concerns. After a generator officially notifies PJM of retirement, system upgrades will be identified to resolve any reliability problems associated with the retirement. If the generator subsequently withdraws the request for retirement, PJM may continue to plan the system to accommodate retirement of the generator. The Capacity Interconnection Rights associated with the retired or reduced plant output capability may survive for up to one year following the actual Deactivation Date. **(PJM Tariff at Part VI, Section 230.3)**

Owners of existing Merchant Transmission Facilities that plan to retire or reduce the capability of a transmission facility must notify PJM in order to address any potential PJM System economic and/or reliability concerns.

2.1.6 Generation and Transmission Interconnection Feasibility Study Analysis and Results

After a valid Generation or Transmission Interconnection Request is received, PJM assigns a System Planning Senior Consultant as the Team Leader to initiate and direct the implementation of the Study phases of the Generator and/or Transmission Interconnection Process (see Attachment C for PJM Generation and Transmission Planning Team Role Clarity Diagram).

Under the direction of the Team Leader, PJM staff, in coordination with any affected Interconnected Transmission Owner(s), will establish a time to hold a Scoping Meeting as described in Section 36.1.5 of the Tariff and the following. The Interconnection Customer is required to choose a primary Point of Interconnection and also has the option to specify a secondary Point of Interconnection to be studied during the Generation or Transmission Interconnection Feasibility Study phase of the Interconnection Request, and also must identify one Point of Interconnection as the primary and the second as the secondary choice. The primary and secondary Points of Interconnection will be studied as follows:

The primary Point of Interconnection will be studied and the Generation or Transmission Interconnection Feasibility Study will follow the requirements as set forth in the Tariff, Section 36.2 and this manual.

The secondary Point of Interconnection will receive a sensitivity analysis and this will be included in the Generation or Transmission Interconnection Feasibility Study. This sensitivity analysis will include definition of the overloads and no estimated costs.

The decision as to the designation of the primary and secondary Point(s) of Interconnection must be communicated to PJM and the Interconnected Transmission Owner(s) prior to completing the Scoping Meeting. If the Interconnection Customer fails to provide these designated options (primary or primary and secondary Point of Interconnection) prior to completion of the Scoping Meeting, PJM shall consider the Interconnection Request as deficient, as described for other cases of deficiency of an Interconnection Request in the Tariff, Section 36.1.4, and will process the Interconnection Request in accordance with the Tariff, Section 36.1.4.

Following the Scoping Meeting, PJM and the Interconnected Transmission Owner will conduct the Generation or Transmission Interconnection Feasibility Study when no deficiencies exist for an individual Interconnection Request. In general, the study will be completed within 90 days during the next Feasibility Study Cycle. If this is not possible, PJM must so notify the Developer and provide an anticipated completion date. PJM, in coordination with any affected Interconnection Transmission Owner(s), shall conduct Generation and Transmission Interconnection Feasibility Studies two times each year (**Tariff at Part VI, Subpart A, Section 36.2 - formerly 36.2 and 41.2, in Part IV**) for completion by:

- January 31, for requests received during the six month period ending September 30 of the preceding year.
- July 31, for requests received during the six month period ending March 31.

The Feasibility Study assesses the practicality and cost of incorporating the generating unit or increased generating or transmission capacity into the PJM system. The analysis is limited to short-circuit studies and load-flow analysis. This study does not include stability analysis. The study also focuses on determining preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.

Results of the study for the requested interconnection service (Capacity Resource or Energy Resource) are provided to the Developer and the affected Interconnection Transmission Owners, and are published on the PJM web site. Confidentiality of the Developer is maintained in these reports, but the location of the project and size (in megawatts) is identified. After reviewing the results of the Generation or Transmission Interconnection Feasibility Study, the Developer must decide whether or not to pursue completion of the System Impact Study.

2.1.6.1 Interconnection Requests associated with Phase Angle Regulators

Phase angle regulators (PAR), also called phase shifting transformers, create a phase shift between primary (source) & secondary (load) side of the device to control the amount of flow through the facility. These devices may be proposed to serve as Controllable A.C. Merchant Transmission Facilities under the Tariff. Inherent to these devices are certain operational characteristics which must be addressed to confirm acceptability of the design and incorporation of the proposed facility in the PJM system.

In order to ensure that the facility does not cause excessive upset to the system in the area of the proposed facility, it is recommended that the initial step size of the facility's output not exceed a quantity of 20MWs, when initially transitioning from zero flow to some specified MW value. Initial output quantities in excess of 20 MWs are studied to determine the impacts to the other facilities near the proposed facility to determine if the initial MW quantity, in excess of 20 MWs, would cause a problem to occur. The study of the impacts associated with this initial step size will begin during the System Impact Study phase of the projects development. If any issues are identified, associated with a step size in excess of 20 MWs, which cannot be resolved, then the customers Interconnection Request will be withdrawn from the New Services Queue.

The controls associated with a PAR must be capable of providing automatic control so that the scheduled MW quantity for the facility is maintained for all contingency conditions which are required to be tested dependent on the type of service requested whether it be capacity or energy injection or firm or non-firm withdrawal rights. Deviations from the scheduled MW quantity can result in charges to the facility as governed by PJM market rules. Beyond automatic control of the facility, the proposed facility controls must allow for a manual mode of operation to hold the angle of the PAR as opposed to maintaining the MW flow in the event this mode of operation is requested by PJM Operations during periods of system upset or emergency. Additionally, the proposed customer facility must be capable of achieving zero flow through the design of the facility by the customer.

Each New Service Request is studied on a summer peak RTEP base case with the case year dependent on the New Services Queue under study. PJM will identify the base case year to be used in the study of a specific queue on its website. Both load flow and short circuit cases will use the same base case year. In some cases, depending upon the age of the study, versions of the models to study the New Service Request may no longer be available to use for certain vintage cases. As this occurs, PJM may need to evaluate the New Service Request on a different year case in order to maintain the ability to properly represent the proposed customer facilities.

All active New Service Requests, are modeled in the load flow case as appropriate.

Generally, Network Upgrades identified for previously completed studies are not modeled in the load flow case so that later queued projects can receive cost allocation, assuming they meet the cost allocation thresholds (see Attachment B). The exception to this is that if a Network Upgrade changes the topology of the system which then requires utilization of the Network Upgrade to ensure new flow patterns are addressed. These topology changes require that a study be conducted with and without the individual upgrade which causes a change in the topology. For short circuit studies, all upgrades which modify topology and any upgrades with impedance changes to the equipment are modeled in the original study case.

The load flow feasibility study is a DC contingency analysis, NERC P0, P1, P2, P4, P5 & P7 contingencies are tested (see Generator Deliverability section of Manual 14B). Each New Service Request in the Feasibility Study phase will be assigned a commercial probability, currently 53%, based on historical data. All projects in the New Services Queue will be studied as a group.

The short circuit Feasibility Study is a breaker duty analysis during which each New Service Request is studied sequentially. No cost allocation for any identified Network Upgrade will be performed during the Feasibility Study for load flow and short circuit analyses.

Any newly identified facility or breaker will be reported; for contributions to previously identified thermal overloads or over-dutied breakers, the project must meet cost allocation rules specified in Attachment B of this manual.

Generation Interconnection Requests that are 20 MWs or less, or for increases in capability of 20 MW or less for existing generation, are governed by Subpart G of Part IV of the Tariff and section 3 of this manual.

The Transmission Provider will coordinate with Affected System Operators the conduct of any study required to determine the impact of a New Service Request on any Affected System as set forth in Sections 202 and 218 of the Tariff. During the Feasibility Study process, an Affected System will be notified of a potential impact for any individual interconnection request, generation or merchant transmission, under study that has $\geq 3\%$ distribution factor (absolute value), $\geq 10\%$ distribution factor (absolute value) for 500 kV and above facilities. The Affected System will also be notified for any Long Term Firm Transmission Service Request under study that has $\geq 3\%$ distribution factor (absolute value) for all facilities. The Notification includes the potential impact, base case year, size in MWs, fuel, Point of Interconnection and study phase.

2.2 Generation or Transmission Interconnection System Impact Study Agreement Execution and Analysis

2.2.1 Impact Study Agreement and Cost

After receipt of the Generation or Transmission Interconnection Feasibility Study results, if the Developer decides to proceed, an executed System Impact Study Agreement must be submitted to PJM with the required deposit as specified in Section 204.3A of the Tariff. If the cost of the System Impact study is reasonably expected to exceed the deposit received before the study begins, PJM will require the Developer to submit the additional deposit.

For an Interconnection Request to maintain its assigned priority, the Developer must execute and return the System Impact Study Agreement (and the required deposit), as well as complete the System Impact Study data form located on PJM's web site. See Attachment G in this manual for a list of the data required to complete this form) within 30 days of receiving the System Impact Study Agreement. If a New Service Customer fails to meet this deadline, the Interconnection Request will be deemed terminated and withdrawn. In general, the study will be completed within 120 days of the date the study begins. If this is not possible, PJM must so notify the Developer, providing an anticipated completion date and an explanation of why additional time is needed.

For generation projects, proof is required at this point of initial application for required air permits, if any, and the Developer must declare whether a generation project is to be connected as a Capacity or Energy Resource.

For Merchant Transmission Facilities, site control must be provided with the System Impact Study Agreement.

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system and an evaluation of their impact on deliverability to PJM load in the particular PJM region where the generator and/or new

transmission facility is located. This Study identifies the system constraints relating to the project and the necessary Attachment Facilities, Local Upgrades, and Network Upgrades. The Study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.

Table 2-2-1: System Impact Study costs

Project size	Required deposit		Portion of deposit that is non-refundable	Maximum deposit
	Fixed portion	Per MW Portion		
>20MW	None	\$500/MW	10%	\$300,000
≥2MW and ≤20MW	\$10,000	None	10%	\$10,000
<2MW	\$5000	None	10%	\$5,000

If a Developer submits an Attachment N-1 in any of the zones listed in Table 2-2-2 below and the standard Tariff deposit is less than the amount shown in the table, the Developer shall provide PJM the difference between the value in Table 2-2-2 and the standard Tariff deposit. If a Transmission Owner zone is not on the table or the value indicates bounded, then PJM expects the standard Tariff deposit will cover the System Impact Study costs. Note however, that a Developer is responsible for actual costs of the study and actual costs may exceed the expected amount.

Table 2-2-2 System Impact Study PJM Expected Costs

TO Zone	Expected Cost (\$) Requests > 20 MW	Expected Cost (\$) Requests ≤ 20 MW
AEP	46K	16K
BGE	50K	Bounded
ComEd	99K	32K
Dayton	25K	Bounded
DL	23K	Bounded
Dominion	26K	15K
FE	42K	16K
PECO	17K	Bounded
PHI	28K	15K
PPL	31K	Bounded
PSEG	38K	Bounded

2.2.1.1 Dynamic Model for stability studies

PJM utilizes manufacturer models to ensure the performance of turbines is properly captured during the simulations performed for stability verification and, where applicable, for compliance with low voltage ride through requirements. Turbine manufacturers provide such models to their customers. The list of manufacturer models PJM has already validated is contained in Attachment G to this Manual.

Manufacturer models may be updated from time to time, for various reasons such as to reflect changes to the control systems or to more accurately represent the capabilities turbines and controls which are currently available in the field. Additionally, as new turbine models are developed, turbine manufacturers provide such new models which must be used in the conduct of these studies. PJM needs adequate time to evaluate the new models in order to reduce delays to the System Impact Study process timeline for the Interconnection Customer as well as other Interconnection Customers in the study group. Therefore, PJM will require that any Interconnection Customer with a new manufacturer model must supply that model to PJM, along with a \$10,000 fully refundable deposit, no later than three (3) months prior to the starting date of the System Impact Study (See Section 2.2.2. below for starting dates) for the Interconnection Request which shall specify the use of the new model. The Interconnection Customer will be required to submit a completed dynamic model study request form (Attachment G-1 of Manual 14A) in order to document the request for the study.

2.2.2 System Impact Study Analysis and Schedule

Relationships are studied between the new generator or the new transmission facility, other planned new generators in the queue, and the existing system as a whole. This study also encompasses an analysis of existing firm and non-firm Transmission Service requests. PJM, in coordination with any affected Interconnection Transmission Owner(s), shall conduct System Impact Studies two times each year (**Tariff at Part VI, Section 205.2 - formerly 36.4.1 and 41.4.1, in Part IV**) commencing on:

- May 1, for requests received during the six month period ending September 30 of the preceding year.
- November 1, for requests received during the six month period ending March 31 of the same year.

PJM may decide to group two or more interconnection requests within one System Impact Study if the proposed projects are in electrical proximity. In situations where more than one generation project violates reliability criteria, cost responsibility for network upgrades to mitigate such violations will be allocated among the projects in the course of the System Impact Study.

The System Impact Study includes AC powerflow analysis, short circuit analysis, and stability analysis. The powerflow analysis can include different sets of analyses at various load levels such as summer peak, light load, and winter peak. All powerflow analysis is performed consistent with PJM Reliability Planning Criteria as described in PJM Manual 14B Attachment D. Similarly, the stability analysis can include different sets of analyses at various load levels such as summer peak, light load, and winter peak.

During the System Impact Study phase of a project, PJM will consider Affected Systems as set forth in Sections 202 and 218 of the Tariff. PJM will again contact Affected Systems, previously identified as having potential for impacts from the PJM projects under study during the Feasibility Study phase, to determine if the Affected System has determined



that any impacts to the Affected System need to be identified in the System Impact Study to the PJM

customer and any need for Affected System reinforcements. The process for next steps associated with these reinforcements vary depending upon the Affected System's provisions and will be discussed with the New Service Customer to determine any requirements which must be adhered to in the Affected System study process. Failure to adhere to the requirements of the Affected System study process will result in the PJM customer being withdrawn from the PJM queue.

Various types of thermal analysis will be performed based on the type of project and its anticipated potential to affect the system. A brief discussion of these studies follows.

Summer Peak Analysis

The PJM Generation Deliverability test is a test performed in accordance with PJM Manual 14B, sections 2.3.10 and Attachments C.6 and C.7. New Service Requests are subject to the PJM Generation Deliverability Test as applicable.

The PJM Load Deliverability test is a test performed in accordance with PJM Manual 14B, sections 2.3.9 and Attachments C.3 and C.4 and C.5. The following New Service Requests are subject to the PJM Load Deliverability test: 1) Storage type Generation Interconnection Requests, depending on size and input of an affected Transmission Owner, 2) Transmission Interconnection Requests requesting Firm Transmission Withdrawal Rights, and 3) requests for Incremental Capacity Transfer Rights arising from a New Service Request as set forth in Attachment F of Manual 14E.

NERC P3 and P6 "N-1-1" analysis is performed in accordance with PJM Manual 14B, section 2.3.8. New Service Requests are subject to "N-1-1" analysis as applicable. Such applicable examples can include but are not limited to a Generation Interconnection Request that would change system topology, a Transmission Interconnection Request requesting Firm Transmission Withdrawal Rights or Firm Transmission Injection Rights, a Firm Point-to-Point Transmission Service Request, or any New Service Request which changes the system topology due to its required Network Upgrades.

Voltage analysis is performed in accordance with PJM Manual 14B, section 2.3.7. New Service Requests are subject to steady-state voltage analysis as applicable.

Light Load Analysis

The light load reliability analysis tests the ability of an electric area to export generation resources to the remainder of PJM during light load conditions. The initial target dispatch is identified as the light load base case initial target dispatch in Manual 14B, Attachment D-2. It should be noted that the initial dispatch must meet the current load requirement of the case and therefore additional resources may need to be dispatched, e.g. natural gas facilities, if the other facilities in an area cannot meet the scheduled load. Due to the nature of the potential to change the initial dispatch assumptions, in the event that a certain type of facility is dispatched in the initial target dispatch, PJM shall dispatch all New Service Requests, with the same fuel type and same TO area as in the original dispatch, during the ramping portion of the studies to determine any new violations. Transmission Interconnection Requests (Firm Transmission Rights only) and Long Term Firm Point-to-Point Transmission Service requests are also included in the light load reliability analysis for New Service Request studies. The contingencies used for light load reliability analysis include NERC TPL category P1, P2, P4, P5, and P7. NERC TPL P0, normal system conditions is also studied. The Generation Deliverability Test performed during light load reliability analysis is performed

in accordance with PJM Manual 14B, section 2.3.10 and Attachments C.6 and C.7, except the ramping limits in Attachment D-2 of Manual 14B are enforced.

Light Load Common Mode Outage Procedure

This portion of the test is similar to the Generator Deliverability test listed in Addendum 2 of section C.7.3 of PJM manual 14B, except the ramping limits in Attachment D-2 of PJM manual 14B are enforced.

Any new overload caused by a New Service Request under study is reported. A New Service Request that contributes to the loading of an existing overload is reported if that New Service Request increases the loading by at least 1% and contributes at least 5MWs or has at least a 5% distribution factor.

The procedure to determine cost allocation for Light Load Analysis associated with New Service Requests is similar to the methods used for Summer Peak Load Flow Analysis set forth in Attachment B of this PJM manual 14A.

Winter Peak Analysis

The winter peak reliability analysis tests the ability of an electric area to export generation resources to the remainder of PJM during winter peak conditions. The winter peak analysis is performed during the System Impact Study phase of the PJM Interconnection Process. The facility ratings used in the winter peak analysis are different than the summer peak analysis. Further details about the facility ratings can be found in section 2.3.13 of the PJM Manual 14B. The contingencies used during this analysis include, NERC category P1, P2, P3, P4, P5, P6, and P7. NERC category P0, normal system conditions will also be studied. The winter peak study initial target dispatch and ramping limits are listed in Attachment D-3 of PJM manual 14B.

The different types of test performed during winter peak analysis include Generation Deliverability Test, Load Deliverability test, Normal System (NERC P0) and N-1 (NERC P1) Events, and N-1-1 (NERC P3 and P6) Events. Further information about these tests can be found in sections D-3.2.4 to D-3.2.7 of Attachment D-3 to PJM manual 14B.

Short Circuit Analysis

All New Service Requests are subject to evaluation as to the need for short circuit analysis. Certain types of New Service Requests may not require analysis for short circuit impacts as the impacts were already captured in the studies associated with the introduction of the generation, e.g. Transmission Service Request studies. The case year used for the study of the fault contributions associated with a New Service Request shall be consistent with the case used in the thermal analysis studies, e.g. summer, peak, light load, etc. Short circuit analysis shall be performed consistent with the requirements of section G.7 of Attachment G to PJM manual 14B.

Stability Analysis

All New Service Requests are subject to evaluations as the need for stability analysis and/or review which will be performed during the System Impact Study phase. For Generation Interconnection Requests a threshold of 20 MW is considered when determining if a stability analysis is required on a generic basis, though in areas with known stability concerns, generation with lower total capability may also be tested. Stability analysis is performed as described in PJM Manual 14B Attachment G.

2.2.3 System Impact Study Results

Results of the study are provided to all Developers who had projects evaluated in the study and to affected Interconnected Transmission Owners and are posted on the PJM web site. While confidentiality obligations will be honored, the identity of the Developers will not be considered confidential in these reports.

The identity of all Developers, the size and the location of projects for which System Impact Studies have been completed are published on the PJM web site.

After reviewing the results of the study, the Developer must decide whether or not to proceed with either the PJM proposed (i) a Generation or Transmission Interconnection Facilities Study or (ii) an Interconnection Service Agreement or Upgrade Construction Service Agreement, whichever is furnished by PJM. If the Developer decides to proceed with the project, the results of the System Impact Study are also rolled into the RTEP Process for development of the RTEP to be submitted to PJM's Board of Managers for approval.

2.3 Generation and Transmission Interconnection Facilities Study Agreement Execution and Analysis

2.3.1 Queue Priority and final agreement issuance and determination of security requirements for moving out of sequence

The Tariff establishes due dates for PJM to issue Feasibility and System Impact Studies. However, upon completion of a Facilities Study, queue priority becomes important for issuing of final agreements to New Service Customers. New Service Customers that are first to cause the need for network upgrades will receive their service agreements before those customer(s) that receive cost allocations. To prevent a lower ordered queue request (or any queue request with cost allocation) from having to commit to agreements and potential unexpected costs without the knowledge of the higher ordered queues decision, PJM will delay the issuing of final agreements for affected projects by approximately one week. This allows time to rescind and restudy the affected lower ordered queue projects if the higher ordered project is withdrawn from the queue.

If a lower ordered queue wishes to proceed ahead of a higher ordered queue for which it shares cost responsibility or may become responsible for an upgrade, then the lower ordered queue must provide Security and/or advance construction for all shared or required upgrades.

2.3.2 Generation and Transmission Interconnection Facilities Study Agreement

Upon completion of the System Impact Study, PJM will furnish either (i) a Generation and/or Transmission Interconnection Facilities Study Agreement to the Developer, along with estimated cost of the study and the estimated time of completion or (ii) an Interconnection Service Agreement or Upgrade Construction Service Agreement. For an Interconnection Request to maintain its assigned priority, the Developer must execute and return the Generation and/or Transmission Interconnection Facilities Study Agreement (and the required deposit) within 30 days of receiving it. If an Developer fails to meet this deadline, the Interconnection Request will be deemed terminated and withdrawn. If the Developer has received an Interconnection Service Agreement or Upgrade Construction Service Agreement, please see discussion in Section 4 of this manual for additional information.

The Generation and/or Transmission Interconnection Facilities Study Agreement will provide the estimated cost responsibility and estimated completion date for the study. It may also define

reasonable milestone dates that the proposed project must meet to retain its Queue Position while PJM is completing the Generation or Transmission Interconnection Facilities Study. See Attachment D for a General Description of the Facilities Study Procedure.

2.3.3 Generation and Transmission Interconnection Facilities Study Cost

As specified in Part IV, Subparts A and B of the Tariff, if the Developer decides to proceed, the executed Generation and/or Transmission Interconnection Facilities Study Agreement must be returned accompanied by the required deposit as specified in Section 206.3 of the Tariff, and also listed in Table 2-3 below.

Table 2-3: Facilities Study costs

Project size	Required deposit
>20MW	The greater of: \$100,000 OR estimated amount of Facilities Study cost for the first three months
>2MW and ≤20MW	\$50,000
≤2MW	\$15,000

2.3.4 Generation and Transmission Interconnection Facilities Study Results

During the Facilities Study phase, the System Impact Study results are retooled as necessary to reflect changes in the New Services Queue such as but not limited to New Service Customers withdrawing from the queue, reducing the size of their projects, choosing different types of equipment, and providing updated equipment parameters, etc.

When completed, the Generation or Transmission Interconnection Facilities Study will document the engineering design work necessary to begin construction of any required transmission facilities. The Generation or Transmission Interconnection Facilities Study will also provide a good-faith estimate of the cost to be charged to the Developer for Attachment Facilities, Local Upgrades and Network Upgrades necessary to accommodate the project and an estimate of the time required to complete detailed design and construction of the facilities and upgrades.

2.4 Types of Network and Local Upgrades

Network Upgrades are modifications or additions to Tariff facilities that are identified during the study process which are required to accommodate an interconnection project. Local Upgrades are modifications or additions to non-Tariff facilities identified during the study process which are required to accommodate an interconnection project. In addition to Network and Local Upgrades, there is a category called Attachment Facilities, which are facilities required to physically interconnect the Interconnection Customer facilities to the system.

In an Interconnection Study Report, Interconnection Service Agreement, and Interconnection Construction Service Agreement, work to accommodate an interconnection is separated into these three categories which are further defined below:

1. Direct Connection Local and Direct Connection Network Upgrades
2. Non-Direct Connection Local and Non-Direct Connection Network Upgrades
3. Attachment Facilities

These classifications are important in order for PJM to determine how much Security should be held for an Interconnection Customer. As explained in Section 4.1.3, Security is held in order to protect the Transmission Owner and other New Service Customers should the Interconnection Customer decide to terminate the new service request after signing the Interconnection Service Agreement or fail to pay invoices for upgrade work.

1. Direct Connection Local and Direct Connection Network Upgrades:

Direct Connection Local or Direct Connection Network Upgrades are greenfield projects, which have no impact or potential impact on the transmission system until the final tie-in is complete. Direct Connection upgrades includes new facilities that are required to interconnect the Interconnection Customer facilities to the existing transmission system which will carry network flows once completed and energized. These upgrades can be constructed without requiring outages of existing, operating transmission facilities. An interconnection switchyard (as shown in the diagram below) would be considered a Direct Connection Upgrade. Once energized, this switchyard will carry network flows.

2. Non-Direct Connection Local or Non-Direct Connection Network Upgrades:

Non-Direct Connection Local or Non-Direct Connection Network Upgrades are **rebuilt, replacements, or upgrades to existing system facilities**. These upgrades require a facility outage to be constructed. Upgrades to terminal equipment, rebuilding a line, or replacing a breaker are considered to be Non-Direct Connection work. PJM will hold full security for the cost of all Non-Direct Connection work in order to protect the Transmission Owner and other New Service Customers should the Interconnection Customer terminate their project.

3. Attachment Facilities:

Attachment Facilities are facilities required to physically interconnect the Interconnection Customer facilities to the system. Attachment Facilities **do not carry network flows**. A generator lead line is an Attachment Facility as it only carries power flow from the generator (see diagram below). Attachment Facilities work can be completed without impacting the affected Transmission Owner's facilities. Generally, a small portion of an Attachment Facility is owned by a Transmission Owner. All Transmission Owner owned Attachment Facilities are subject to Schedule E charges in an ISA (see M14A Section 4.1).

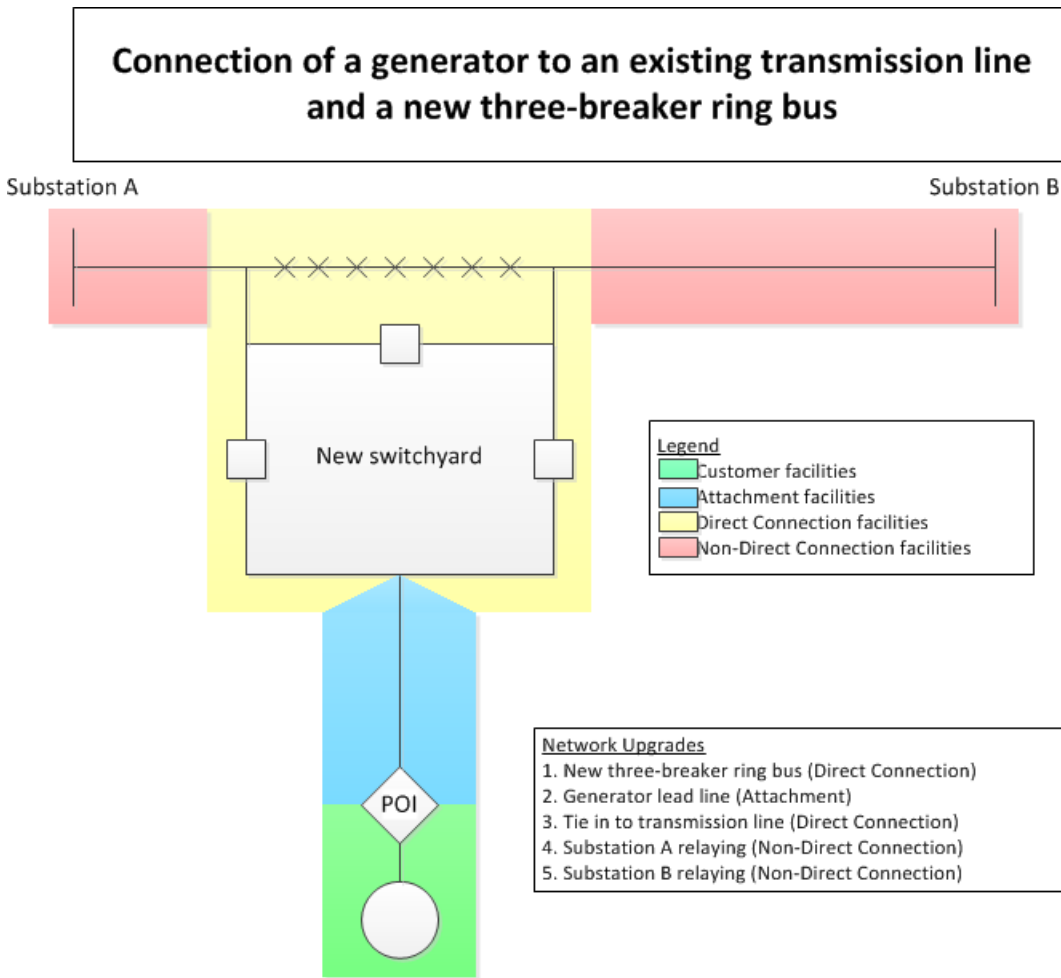


Exhibit 2: Types of Network and Local Upgrades

2.5 Transfer of Capacity Interconnection Rights

2.5.1 Transfer of Capacity Interconnection Rights (CIRs)

In order for the holder of Capacity Interconnection Rights to transfer rights under Tariff section 230, the holder of the rights must have completed the following:

- constructed all necessary system upgrades identified in the ISA or WMPA, and
- maintained the rights as required by the Tariff.

2.5.1.1 Transfer of CIRs Prior to commercial operation

CIRs under study or CIRs from an ISA that are associated with a facility or unit(s) which has not become commercial are non-transferrable. In these cases, the owner of the queue position can sell, or assign the queue project to another entity.

2.5.1.2 Transfer of CIRs from an Operating Unit

For existing Capacity Resources that wish to transfer CIRs and that meet the requirements identified above, a letter to PJM must be provided by the assignor of the rights indicating the transfer amount and to whom the rights are transferring. If the rights are not being transferred at the same Point of Interconnection, then the rights will be transferred through studies performed by PJM that will determine the total CIRs available at the new location. The assignee of the rights must be able to meet all Tariff operating requirements. A new queue position is required for PJM to verify that the unit receiving the rights is capable of meeting all requirements (e.g. power factor) at the new CIR level.

2.5.1.3 Transfer of CIRs from a deactivated unit

If the owner of an existing unit that is to be deactivated wants to transfer their rights to a new unit, they must submit a new queue request within one year of deactivation. Failure to submit a new queue request within one year of the deactivation will result in the loss of the CIRs. If the CIRs are transferred to another owner, a letter to PJM must be provided by the assignor of the rights indicating the transfer amount and to whom the rights are transferring. A queue request from the assignee of the CIRs must be received within one year of the deactivation of the transferring unit. If the rights are not being transferred at the same Point of Interconnection, then the rights will be transferred through studies performed by PJM that will determine the total CIRs available at the new location.

2.5.2 CIR Transfer Process

The following processes will be followed to determine the amount of CIRs which can be transferred from an existing operational generator, to an existing or new resource in order to increase or provide CIRs to an existing or new resource. In all cases the transfer of rights will require that the customer or owner enter the New Services Queue with an Interconnection Request.

For the study of the transfer of CIRs as it affects thermal constraints, all load flow studies will be performed in the queue to which the rights are to be transferred up to the Queue Position immediately preceding the project which is seeking to receive the transferred rights (the generator from which the rights are to be transferred would be online during these studies). PJM will then turn off the generator with the existing rights, make the unit unavailable for dispatch, and then study the new Interconnection Request to determine the thermal impacts of the new Interconnection Request. This analysis will insure that any Capacity Interconnection Rights owned by the existing generator will be used by the new Interconnection Request.

For the Study of short circuit impacts to the system, studies will be performed in order to determine the impact on the increase in fault current for all facilities associated with any new Interconnection Request. Any reinforcement(s) which are determined to be required for the new generator will be reviewed to determine if the existing generator's contribution causes the need for the reinforcement, and if the reinforcement would not be required if the existing unit was removed from the study. The new Interconnection Request would not be required to provide reinforcement to the system if the new Interconnection Request does not cause the need for the reinforcement when the existing unit is removed.

For the study of stability impacts to the system, the existing generator would not be dispatched during the study of the new Interconnection Request.

2.6 Work Papers

The Tariff requires PJM to provide New Service Customers access to the applicable PJM base case data. Base case data is defined in Tariff 36.1.7 to only include upgrades and New Service Requests that are included in the RTEP. The customer requesting the PJM base case data must first complete all necessary Critical Energy Infrastructure Information, Non-Disclosure Agreements and other requirements necessary to obtain the modeling information.

Upon completion of a study report, the Tariff provides that PJM will provide New Service Customers work papers upon request. Work papers are documents, data, and other information developed by PJM based on confidential documents, data or information from PJM Members or New Service Customers that were used in the development of each phase study and that PJM can make public upon completion of a study under the requirements of Operating Agreement 18.17. Generally, work papers include all files necessary for a customer to modify the base case and duplicate the results obtained by PJM in the queue studies. Other examples of work papers would be the initial and final limiting element and associated ratings used in a study. Since a new service customer is paying for upgrades, they are entitled to the rating of the limiting element as rating information is important to determining the financial rights that may be awarded. Work papers also can include information used to develop an upgrade cost. However, if an upgrade cost was developed using a deskside estimate, no additional detail is required to be generated. For example, if a reconductor was required for a five mile line and was estimated based on past experience to cost about \$1M/mile, no further cost detail is required to be created. Work papers do not include documents, data or information desired by an entity that were not created by PJM or were not used in the production of a study.

Section 3: Small Resource Interconnection Process

In this section you will find the following:

- A description of the small resource interconnection process (see “*Small Resources (20 MW or less)*”).
- Specific provisions applicable to resources of 10 MW or less (see “*Specific Provisions for Resources of 10 MW or Less*”).
- Specific provisions applicable to resources greater than 10 MW up to 20 MW (see “*Specific Provisions for Resources Greater than 10 MW up to 20 MW*”).

3.1 Small Resources (20 MW or less)

3.1.1 Pre-application Process for New Generation Resource Additions of 20 MW or Less or Additions to Existing Generation Resources Not to Exceed 20 MW in Aggregated Maximum Facility Output

The following projects may follow the pre-application process if selected by the potential Interconnection Customer:

- 20 MW or less and
- Connecting to FERC jurisdictional facilities

There are two options for the prospective Interconnection Customer gathering information:

- Informal request of PJM contact listed on PJM’s website, where PJM contact will utilize existing interconnection studies to provide information or
- Formal written request

The prospective Interconnection Customer must provide electrical system information including relevant system studies, and other materials useful to understanding the interconnection at a particular point on the Transmission Provider’s system with a formal written request form and a non-refundable processing fee of \$300. The Transmission Provider will evaluate whether the proposed site’s Point of Interconnection will be on a FERC jurisdictional facility within five (5) business days. If it is determined to not be on a FERC jurisdictional facility, the Transmission Provider will inform the prospective Interconnection Customer that the proposed interconnection site is not jurisdictional and return any deposits submitted for the pre-application. If it is determined to be on a FERC jurisdictional facility, Transmission Provider will provide pre-application report to the prospective Interconnection Customer within twenty (20) business days after the jurisdictional determination. The pre-application report provided by the Transmission Provider is non-binding, does not confer any rights, and still requires the Interconnection Customer to successfully apply to interconnect to the Transmission Provider’s system (Tariff at Part IV, Section 109).

3.1.2 Small Generation Interconnection Queue Submittal

Requests for the interconnection of new resources which are 20 MW or less, or increases in capability of 20 MW or less to existing generation (over a 24 month period) may be processed through expedited procedures. (Refer to Part IV, Subpart G of the Tariff.) Expedited procedures

are defined in the Tariff for five categories of these “very small resource” additions; permanent Capacity Resource additions of 20 MW or less, permanent Energy Resource additions of 20 MW or less but greater than 2 MW (synchronous) or greater than 5 MW (inverter-based), temporary Energy Resource additions of 20 MW or less but greater than 2MW, permanent and temporary Energy Resource additions of 2 MW or less (synchronous) or 5 MW or less (inverter-based), and certified small inverter-based facility additions not greater than 10 kW.

3.1.3 Study Requirements and Cost

In all cases, with the exception of requests for (i) interconnection falling under the process defined in the Tariff applicable to permanent and temporary Energy Resource additions of 2MW or less and (ii) interconnection falling under the process defined in the Tariff applicable to certified small inverter-based facility additions no larger than 10 kW, an Interconnection Customer must submit an Interconnection Request in the form of an executed Generation Interconnection Feasibility Study Agreement (**Tariff at Part VI, Attachment N**) and provide the same information required for larger resources. Deposit requirements are listed in the table below (Table 3-1-1) (**Tariff at Part IV, Section 112**). Further:

- For resources of 2 MW or less (synchronous) or 5 MW or less (inverter-based), an Interconnection Customer must submit a completed Form of Screens Process Interconnection Request (**Tariff at Part IV, Section 112A, Attachment Y**). See table 3-1-3 below for deposit requirements.
- For Certified Inverter-Based resources no larger than 10 kW, an interconnection customer must submit a completed Form of Interconnection Service Agreement for Certified Inverter-Based Facility (**Tariff at Part IV, Section 112B, Attachment BB**) and a non-refundable processing fee of \$500.

Table 3-1-1: Small Generation Interconnection Process deposit requirements (Interconnection Requests for a Capacity resource \leq 20 MW or a temporary Energy Resource of 20 MW or less but greater than 2 MW (synchronous) or up to 5 MW (inverter-based))

Month of New Services Queue	Deposit	Portion to be held as non-refundable
1 st - 4 th	\$10,000	10%
5 th	\$12,000	10%
6 th	\$15,000	10%

If a Developer submits an Attachment N in any of the zones listed in Table 3-1-2 below, if the standard Tariff deposit is less than the amount shown in the table, the Developer shall provide PJM the difference between the value in Table 3-1-2 and the standard Tariff deposit. If a Transmission Owner zone is not on the table, then PJM expects the standard Tariff deposit will cover the Feasibility Study costs. Note however, that a Developer is responsible for actual costs of the study and actual costs may exceed the expected amount.

Table 3-1-2 Feasibility Study Expected Costs for Attachment N submitted Small Generation Interconnection Requests Transmission Owner Zone	Expected Costs (\$)
AEP	16K
FE	14K
ComEd	12K
PECO	11K

Table 3-1-3: Small Generation Interconnection Process deposit requirements (Interconnection Requests for a new permanent or temporary Energy Resource of 2MW or less (synchronous) or up to 5 MW (inverter-based))

Month of New Services Queue	Deposit	Portion to be held as non-refundable
1 st - 4 th	\$2,000	10%
5 th	\$3,000	10%
6 th	\$5,000	10%

The deposit associated with the submission of the executed System Impact Study Agreement shall be in accordance with the requirements of Section 204.3A of the Tariff, which is also listed below in Table 3-1-4.

Table 3-1-4: System Impact Study Deposit

Project size	Required deposit	Portion to be held as non-refundable
>2MW and ≤20MW	\$10,000	10%
≤2 MW	\$5,000	10%

Note:

See Table 2-2-2 for expected costs for System Impact Studies for small generation.

The Generation Interconnection Facilities Study deposit amount shall be in accordance with the requirements of Section 206.3 of the Tariff, which is also listed in Table 2-3.

3.1.4 Expedited and/or Combined Study Analysis

Analysis conducted during the Generation Interconnection Feasibility and System Impact Studies will be expedited (to the degree possible) for new permanent Capacity Resources of 20 MW or less, or permanent Energy Resources of 20 MW or less, or increases of 20 MW or less

to existing resources over any consecutive 24 month period (**Tariff at Part VI, Section 36.1.02 - formerly Section 36.12, in Part IV**).

Power flow analysis will be performed based on a limited contingency set to identify the impact of the resource on the local system and any known violations in the area. Deliverability tests will only be performed for small capacity resources in areas where margins are known to be limited. Similarly, stability analysis will only be performed for small resources where existing stability margins are limited. Generation Interconnection Facilities Studies for small resources can only be expedited consistent with the scope of the required transmission facility additions and upgrades. A small generator interconnection or upgrade may qualify for the expedited study process if it meets the criteria described in Subpart G of the Tariff. Generally, if no load flow or short circuit network impacts are identified and there are no other projects in the vicinity of the small resource addition, a Combined Feasibility and Impact Study (a/k/a a combined study) can be issued to the Interconnection Customer. If a combined study report is being considered, the customer must provide the following within ten (10) business days of the Feasibility Study Scoping Meeting:

- System Impact Study Data
- Deposit adjustment, if required (the greater of the Feasibility Study or Impact Study deposit)

In order to consider a project for a combined study, the Interconnection Customer will need to select only one (1) Point of Interconnection (POI). No secondary POI will be considered for a combined study.

Analysis and design normally performed within the context of Generation Interconnection Feasibility, System Impact Studies will be performed within one study. Limited power flow analysis will be performed to ensure that local contingency criteria are not violated. Short circuit calculations will be performed to ensure that circuit breaker capabilities are not exceeded. The Transmission Owner, or contractors acting on their behalf, will evaluate the engineering details of the physical attachment of the resource, as well as the relaying and metering associated with the resource to ensure a safe and reliable interconnection. All very small resource interconnections require the execution of Interconnection Service Agreements. Permanent, small Capacity Resources and Energy Resources will execute the same form of Interconnection Service Agreement as required for larger resources. A modified form of the Interconnection Service Agreement will be executed for temporary Energy Resources that reflect their interconnection status and their rights with respect to participation in the PJM markets.

Tariff section 212.4 states that the tendered ISA (or WMPA) must be executed by the Interconnection Customer within 60 days after receipt of the study report. PJM issues both the study report and ISA or WMPA at the same time to give the Interconnection Customer the 60 day period to review both the report and agreement(s). In the case of a combined study report (assuming no Facilities Study is required), PJM will need additional time to create the required agreement(s) and get necessary legal review prior to issuing the report and agreement(s) to the customer. Because of the additional time for legal reviews, the targeted due date for the report and agreement to be delivered to the Interconnection Customer will be three (3) months after the Tariff due date for the Feasibility Study.

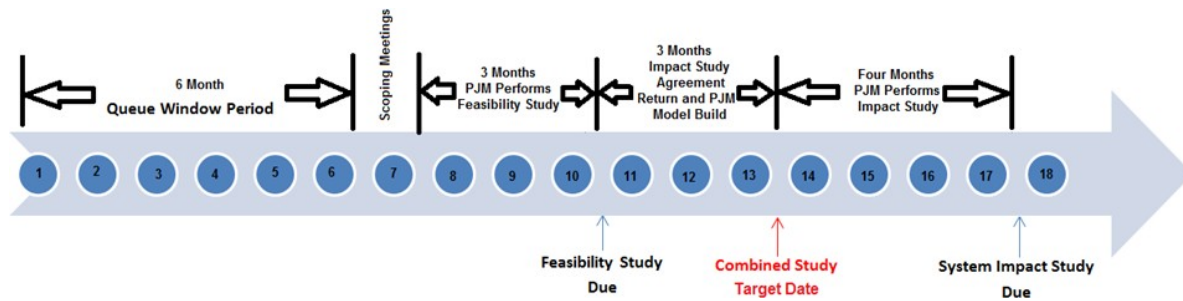


Exhibit 3: Combined Study Target Date

3.2 Specific Provisions for Resources of 10 MW or Less

Under certain circumstances, requests for the interconnection of new resources of 10 MW or less may be expedited through the use of pre-certified generation equipment and systems that meet IEEE Standard 1547 technical requirements. See Attachment E for PJM “Small Generator (10 MW and Below) Technical Requirements and Standards” for full details of the specific provisions that apply to all new generator interconnections with an aggregate size of 10 MW and below at the Point of Interconnection.

3.3 Specific Provisions for Resources Greater than 10 MW up to 20 MW

Requests for the interconnection of new resources greater than 10 MW up to 20 MW may also qualify for certain Applicable Standards based on the core IEEE Standard 1547 technical requirements. See Attachment E-1 for PJM “Small Generator (greater than 10 MW up to 20 MW) Technical Requirements and Standards” for full details of the specific provisions that apply to all new generator interconnections with an aggregate size of greater than 10 MW up to 20 MW at the Point of Interconnection.

Section 4: Interconnection Service Agreement and Construction Service Agreement Execution and Other Agreements

In this section you will find the following overviews of the requirements for Interconnection Service Agreements and Interconnection Construction Service Agreements:

- A description of the Interconnection Service Agreement (see “Interconnection Service Agreement”).
- A description of the Interconnection Construction Service Agreement (see “Interconnection Construction Service Agreement”).
- A description of other agreements (see “Other Agreements”).

4.1 Interconnection Service Agreement

After the Generation or Transmission Interconnection Facilities Study is completed (or, if no Interconnection Facilities Study is required, upon completion of the System Impact Study), the Transmission Provider (“PJM”) will furnish an Interconnection Service Agreement (in the form included in Part VI, Attachment O to the Tariff) to be executed by the Developer and any affected Interconnected Transmission Owner(s). The Interconnection Service Agreement (“ISA”) defines the obligation of the generation or transmission Developer regarding cost responsibility for any required system upgrades. The ISA also confers the rights associated with the interconnection of a generator as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission interconnection customers, the ISA confers transmission injection and withdrawal rights (Merchant D.C. and/or Fully Controllable A.C. transmission projects) and applicable incremental delivery, available transfer capability revenue and auction revenue rights. The ISA further identifies any changes in construction responsibility from the Standard Option for Transmission Owner Interconnection Facilities due to the Interconnection Customer/Developer exercising the Negotiated Contract Option or Option to Build.

Upon issuance of the ISA, PJM team leadership for the project is transferred from the study phase System Planning Senior Consultant to an Interconnection Coordination Senior Consultant for the project Interconnection and Construction phases (see Attachment C for PJM Generation and Interconnection Planning Team Role Clarity Diagram). For leadership continuity, the study phase team leader continues active participation in the project as a member of the Interconnection and Construction team.

For an Interconnection Request to maintain its assigned priority, the Developer must respond within 60 days of receiving the ISA. To proceed with the project, the Developer must provide PJM with a Letter of Credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the Developer is responsible. The Developer must also respond by:

- Executing and returning the Interconnection Service Agreement, or
- Requesting dispute resolution, or
- Requesting, under certain circumstances, that the Interconnection Service Agreement be filed unexecuted.

Further details regarding each of the three response actions may be found in Part VI of the PJM Tariff, available from FERC or on the PJM web site at <http://www.pjm.com/home.aspx>.

Additionally, within the same 60-day period, the Developer must demonstrate:

- Completion of a fuel delivery agreement and water agreement, if necessary.
- Control of any necessary rights-of-way for fuel and water interconnections, if necessary.
- Acquisition of any necessary local, county, and state site permits.
- A signed memorandum of understanding for the acquisition of major equipment.

PJM may also include other reasonable milestone dates for events such as permitting, regulatory certifications, or third-party financial arrangements. Milestone dates may be extended by the PJM in the event of delays not caused by the Interconnection Customer, such as unforeseen regulatory or construction delays.

Additionally, PJM will again ensure that the Generation and/or Transmission Interconnection Customer has access to the Applicable Technical Requirements and Standards of the Interconnected Transmission Owner(s) for parallel operation of generators with the Interconnected Transmission Owner(s) systems and other matters generally included in good utility practice. Technical requirements for generator and transmission interconnections include but are not limited to:

- Engineering design requirements and standards
- Interconnection protection requirements
- Generator under-frequency trip settings to coordinate with automatic under-frequency load shedding schemes
- Voltage control and reactive output requirements (Tariff at Part VI, Section 4.7 in Att. O, App. 2 - formerly Section 54.7, in Part IV)
- Data and control requirements for transmission system operation
- Equipment specifications and suppliers
- Construction requirements and standards
- Engineering, procurement and construction process requirements and standards

Pursuant to section 1.2C of the Tariff, PJM makes documents containing Applicable Technical Requirements and Standards for each Interconnected Transmission Owner available through its internet site at <http://pjm.com/planning/design-engineering/to-tech-standards.aspx>.

PJM will file the Interconnection Service Agreement in compliance with applicable Commission guidelines. If the Developer has requested dispute resolution or unexecuted filing, construction of facilities and upgrades shall be deferred until any disputes are resolved, unless otherwise agreed by the Developer and the affected Interconnected Transmission Owner(s).

4.1.1 Interim Interconnection Service Agreements

Under certain circumstances, a Developer for an Interconnection Service Agreement may wish to initiate project construction activities on an expedited basis prior to completion of

the Generation or Transmission Interconnection Facilities Study. One example of such a circumstance is to request that orders be placed for equipment or materials that have a long lead time for delivery. To initiate such an advance of construction activities, the Developer may request execution of an Interim Interconnection Service Agreement (Tariff at Part VI, Attachment O-1) for those construction activities being advanced.

The Interim ISA would bind the Developer for all costs incurred for the construction activities being advanced pursuant to the terms of the Tariff. While PJM agrees to provide the Developer with the best estimate (determined in coordination with the affected Transmission Owner(s) of the new facility costs and other charges that may be incurred for the work being advanced, such estimate shall not be binding and the Developer must agree through execution of the Interim ISA to compensate PJM and the affected Transmission Owner(s) for all costs incurred due to those activities that were advanced.

4.1.2 Interim ISA vs. ISA with Interim Rights

The Tariff, in section 211, allows for projects under study to advance ordering long lead items and advance construction by the Transmission Owner.

Advanced construction for New Facilities

Tariff Attachment O-1, the Interim ISA, is available to accomplish advanced ordering of long lead items. If advanced construction is requested, Tariff Attachment O-1, the Interim ISA, must be used in conjunction with Tariff Attachment P, the Construction Services Agreement. Interim ISAs do not permit operations to occur as they do not include provisions and appendices required for operations.

Advanced construction for generators with fully executed final agreements

FERC requires only one final agreement can persist at any one time. If advanced construction or long lead item ordering is required, a Tariff Attachment O, an ISA will be developed for execution and will supersede the existing agreement in place for that facility. The ISA will collect necessary Security, identify the work or long lead items to be purchased. If advanced construction is required, Tariff Attachment P, a CSA will accompany the ISA. See below if advanced construction and operations are requested.

Requesting operations in advance of the study year

As identified previously, Interim ISAs do not permit operations. In order to allow rights to be exercised in advance of the base case year, an ISA with interim rights is required. An ISA with interim rights allows a generator to operate prior to the base case year(s), pending results of annually performed interim deliverability studies. It is incumbent upon a Developer wishing to exercise rights in the PJM Market prior to their base case year to request interim studies through their assigned PJM project manager.

Note:

Further information on all required studies and the Interconnection Service Agreement may be found in Part VI, of the PJM Tariff (Tariff at Part VI, Section 212 - formerly Subpart A at 36.8, in Part IV for Generation Interconnections, Tariff at Part VI, Section 212 – formerly Subpart B at 41.7 for Transmission Interconnections, Tariff at App. 2 of Att. O – formerly Subpart E for Standard Terms and Conditions and Attachment O for the form of Interconnection Service Agreement in Part VI – formerly Part IV) available in the library section of PJM's web site.

4.1.3 Security Requirements

In accordance with Section 212.4 of the Tariff, at the time the Interconnection Customer executes the Interconnection Service Agreement (ISA), Interim ISA, Wholesale Market Participation Agreement (WMPA), or Upgrade Construction Service Agreement (UCSA), they must provide Security (cash, letter of credit, or other reasonable form of Security) that names PJM as the beneficiary for any work required and specified in the agreement to be performed on behalf of the customer or for Network Upgrades (work that may be relied on by other New Service Customers to be completed) or for cost allocations towards Network Upgrades.

PJM requires Security to be held in order to:

- Protect Transmission Owner(s) and ratepayers in the event the Interconnection Customer fails to pay for any construction work performed by the Transmission Owner(s) and terminates their project. The Security will allow the Transmission Owner(s) to restore their system to a reliable state.
- Protect other New Service Customers in the event the Interconnection Customer terminates the project after executing an ISA, Interim ISA, WMPA, or UCSA when another New Service Customer is relying on those facilities. The Security would cover the cost of the Transmission Owner(s) to complete the required Network Upgrades that other New Service Customers need.

The Security amount is determined by PJM and is estimated to be the sum of the cost of:

- Required Non-Direct Connection Local Upgrades and Non-Direct Connection Network Upgrades²
- Any Network Upgrades³ that Transmission Owner(s) will be responsible for constructing that the customer has cost allocations towards
- Required Attachment Facilities, Direct Connection Local Upgrades and Direct Connection Network Upgrades⁴ work that the Interconnected Transmission Owner expects to complete during the first three months of construction work in earnest.

For Non-Direct Connection Network and Local Upgrades, as the construction is completed and paid, Security will be reduced appropriately. If Security is paid in cash, an Interconnection Customer can elect to allow Security to be worked down during construction, as long as adequate Security remains after the payment. For Direct Connection Network and Local Upgrades and Attachment Facilities, Security is not reduced until all work is completed. Thus, if a project is completed, all Security will be returned to the Interconnection Customer upon initial operation.

If an Interconnection Customer fails to timely execute the Interconnection Service Agreement, meet the applicable Tariff 212.5 milestones identified in the ISA, or provide the required Security, the Interconnection Request will be deemed terminated and withdrawn.

Deferred Security:

The Interconnection Customer may request to defer providing their Security for up to 120 days after the Interconnection Customer executes the Interconnection Service Agreement. Any

² Refer to Section 2.4 for Network Transmission Upgrades

³ Refer to Section 2.4 for Network Transmission Upgrades

⁴ Refer to Section 2.4 for Network Transmission Upgrades

Network Upgrades that are being relied upon or could be relied upon within the year by another New Service Customer that have a completed System Impact Study are not available for this Deferred Security option.

The Interconnection Customer can request the Transmission Owner to commence procurement and / or engineering design of Transmission Owner work during the deferred Security period. The Interconnection Customer must pay a deposit of \$200,000 or 125% of the estimated costs that will be incurred during the 120 day period, whichever is greater, to fund the continued design and procurement activities for the upgrades. \$100,000 is non-refundable. The Deferred Security deposit is separate and additional to the Security required for the ISA and cannot be used to offset the requirement for final Security. If there are any remaining non-refundable deposit monies, they will be returned to the Interconnection Customer upon initial operation. If the project terminates before initial operation, the non-refundable money is forfeited.

4.1.4 Agreement Milestones

Project specific milestones are included in the agreement. The purpose of ISA milestones is to ensure the Interconnection Customer is performing their due diligence and making progress with the installation and completion of their generator facilities. PJM may add or remove milestones to an ISA as required, but at a minimum new generation projects' ISAs include the following:

- Substantial Site work completed
- Delivery of major electrical equipment
- Commercial Operation

All milestones contain the phrase “on or before” the milestone date. The “on or before” allows a customer to identify a most likely schedule while accounting and allowing for potential schedule delays. If the milestone date in the ISA allows for unforeseen delays and the project actually is completed on the aggressive timeline, then the on or before agreement language allows for them to commence operations ahead of the milestone (this is a positive outcome and accounts for the greatest in-service probability). However, if PJM includes the most aggressive schedule date as the milestone, then PJM must breach the customer if they miss the milestone date (a very likely breach event since the left-most arrow, based on the area under the bell curve is the least probable and there is great potential for in-service to occur later). Even the most likely schedule date has a 50/50 chance as to whether PJM may have to breach the customer for missing a milestone date.

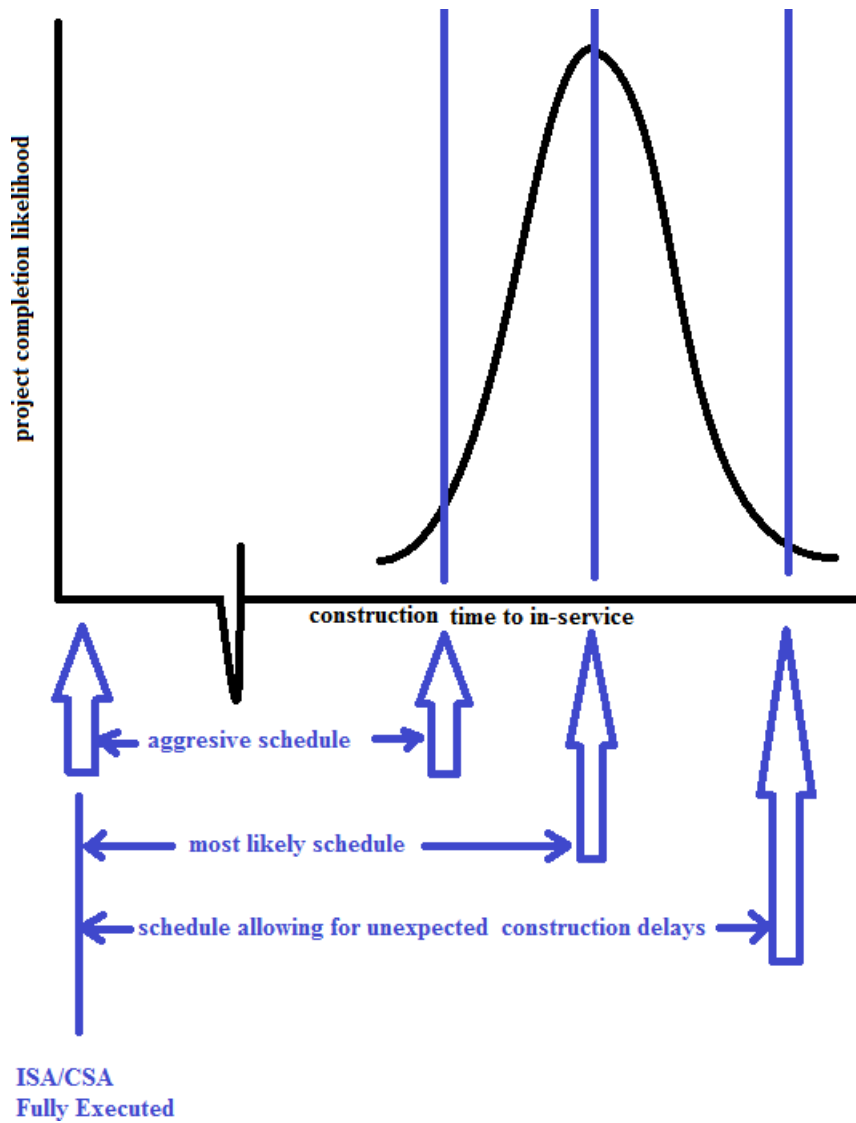


Exhibit 4: Milestones v. Construction Probability

4.2 Interconnection Construction Service Agreement

The construction of any Interconnection Facilities required to interconnect a generator or transmission project with the PJM Transmission Grid shall be performed in accordance with the Standard Terms and Conditions as specified in an Interconnection Construction Service Agreement to be executed among the Developer for Transmission Service (Generation or Transmission Interconnection Customer), PJM and the affected Interconnected Transmission Owner(s). The form of an Interconnection Construction Service Agreement may be found in the PJM Tariff as Attachment P.

The party(ies) responsible for installing the Generator and/or Transmission Interconnection Facilities and/or Network Upgrade Facilities shall use Reasonable Efforts to install those facilities in accordance with an agreed Schedule of Work.

Note:

Further information on all terms and conditions to be incorporated and made part of an Interconnection Construction Service Agreement may be found in Part VI, Att. P, App. 2 of the PJM Tariff (formerly Subpart F for Standard Construction Terms and Conditions and Attachment P for the form of an Interconnection Construction Service Agreement in Part VI) available in the Library section of PJM's web site.

4.2.1 Option to Build

In the event that the Interconnection Customer and the Interconnected Transmission Owner are unable to agree upon the terms of an Interconnection Construction Service Agreement, or if mutually agreed by and between the Interconnection Customer and the Interconnected Transmission Owner, the Interconnection Customer shall have the right, but not the obligation ("Option to Build"), to design and install all or any portion of the Transmission Owner Interconnection Facilities. To exercise this Option to Build, the Interconnection Customer must provide PJM and the Interconnected Transmission Owner written notice of its election to exercise the option by no later than 37 days after the Interconnection Customer's execution of the Interconnection Service Agreement. The Interconnection Customer must request Option to Build per the terms of the Interconnection Construction Service Agreement.

If exercising Option to Build, the Interconnection Customer must select contractors to perform such work from the Transmission Owner's "List of Approved Contractors". Each Transmission Owner's "List of Approved Contractors" is available on the PJM website. If a contractor desired to be used by the Interconnection Customer is not on the "List of Approved Contractors," the customer can request the Transmission Owner evaluate the contractor for acceptability.

The Interconnection Customer is responsible for obtaining all necessary permits, authorizations, and land rights for the construction and installation of the Transmission Owner Interconnection Facilities that it is building. The Interconnection Transmission Owner shall assist the Interconnection Customer in acquiring such necessary permits, authorizations, and land rights if requested by the Interconnection Customer.

If the Interconnection Customer selects Option to Build for design, procurement, construction, and installation of (a) any Transmission Owner Interconnection facilities that are Local Upgrades or Network Upgrades to existing transmission system facilities or (b) Transmission Owner Interconnection Facilities that are to be located on land or in right-of-way owned or controlled by the Interconnected Transmission Owner, the following conditions apply:

- All work must be performed by contractors listed on the Interconnected Transmission Owner's "List of Approved Contractors".
- The Transmission Owner must have full site control of and reasonable access to its property at all times.
- The Transmission Owner has the right to have representatives to supervise work done on its property/facilities and stop or order corrective measures to any work that reasonably could be expected to have an adverse effect on reliability, safety, or security.

- The Interconnection Customer and its contractors must comply with the Interconnected Transmission Owner's safety, security and work rules, and environmental guidelines applicable to the area of construction activity.

Upon completion of the construction and installation of the Option to Build facilities, and prior to energization, the Interconnection Customer must have the constructed facilities inspected and tested by an authorized electric inspection agency or qualified third party acceptable to the Interconnected Transmission Owner. The Interconnected Transmission Owner and PJM have the right to attend, observe, and obtain written results of such tests.

4.2.2 General Timeline

If the Interconnection Customer chooses to exercise the Option to Build, the Interconnection Parties must adhere to the following timeline:

- The Interconnection Customer must provide PJM and the Interconnected Transmission Owner with written notice of its election to exercise the option by no later than 7 days after the date that is **30 days** after the Interconnection Customer's execution of the Interconnection Service Agreement.
- Within **10 days** after notifying PJM of its election to exercise Option to Build, Interconnection Customer shall solicit bids from one or more Approved Contractors.
- Prior to commencing construction, the Interconnection Customer shall submit to the Interconnected Transmission Owner and PJM initial drawings, certified by a registered professional engineer, of the Transmission Owner Interconnection Facilities that the Interconnection Customer arranges to build under the Option to Build. After consulting with the Interconnected Transmission Owner, PJM shall provide comments on such drawings to the Interconnection Customer within **60 days** after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved.
- Each Constructing Entity shall issue reports to each other Construction Party on a **monthly basis** regarding the status of the construction and installation of the Interconnection Facilities. Each Construction Party shall promptly identify, and shall notify each other Construction Party of, any event that may delay completion or may significantly increase the cost of the Interconnection Facilities. Within **15 days** of such notification, PJM shall convene a technical meeting of the Construction Parties to evaluate schedule alternatives.
- Interconnection Customer and the Interconnected Transmission Owner shall coordinate the timing and schedule of all inspection and testing of the Interconnection Facilities. If inspection or testing identifies any defects or failures to comply with Applicable Standards of (i) Interconnection Facilities constructed by the Interconnection Customer, Interconnected Transmission Owner shall notify the Interconnection Customer and PJM of such defects or failures within **20 days** after receipt of the results of such inspection or testing, or (ii) Interconnection Facilities constructed by the Interconnected Transmission Owner, Interconnected Transmission Owner shall take appropriate action to correct any such defects or failures within **20 days** after it learns thereof.
- Within **10 days** after satisfactory inspection and/or testing of Interconnection Facilities built by the Interconnection Customer/Developer, the Interconnected Transmission Owner shall confirm in writing to the Interconnection Customer and PJM that the successfully inspected and tested facilities are acceptable for energization.

- Within **5 days** after determining that Interconnection Facilities have been successfully energized, the Interconnected Transmission Owner shall issue a written notice to the Interconnection Customer accepting the Interconnection Facilities built by the Interconnection Customer that were successfully energized.
- Within **30 days** after the Interconnection Customer's receipt of notice of acceptance of the Interconnection Facilities, the Interconnection Customer shall deliver to the Interconnected Transmission Owner, for the Interconnected Transmission Owner's review and approval, all of the documents and filings necessary to transfer to the Interconnected Transmission Owner title to any Transmission Owner Interconnection Facilities constructed by the Interconnection Customer, and to convey to the Interconnected Transmission Owner any easements and other land rights to be granted by the Interconnected Customer that have not by then already been conveyed. The Interconnected Transmission Owner shall review and approve such documentation, such approval not to be unreasonably withheld, delayed or conditioned.
- Within **30 days** after its receipt of the Interconnected Transmission Owner's written notice of approval of the documentation, the Interconnection Customer, in coordination and consultation with the Interconnected Transmission Owner, shall make any necessary filings at the FERC or other governmental agencies for regulatory approval of the transfer of title.
- Within **20 days** after the issuance of the last order granting a necessary regulatory approval becomes final, the Interconnection Customer shall execute all necessary documentation and shall make all necessary filings to record and perfect the Interconnected Transmission Owner's title in such facilities and in the easements and other land rights to be conveyed to the Interconnected Transmission Owner.

4.2.3 Summary of General Conditions

In addition to the other terms and conditions applicable to the construction of facilities under the Option to Build, the Generation and/or Transmission Interconnection Customer must also:

- Obtain all necessary permits and authorizations
- Obtain all necessary land rights
- Accept the exclusive right and obligation of the Interconnected Transmission Owner to perform line tie-in work and to calibrate remote terminal units and relay settings
- Follow accepted procedures to have those facilities that it builds successfully inspected, tested and energized
- Arrange for all work to be performed by contractors, and using equipment manufacturers or vendors that are listed on the Interconnected Transmission Owner's List of Approved Contractors
- Allow the Interconnected Transmission Owner full site control and reasonable access to its property at all times
- Allow the Interconnected Transmission Owner to have a reasonable number of appropriate representatives present for all work done on its property/facilities and the right to stop work or order corrective measures for any work with an adverse effect on reliability, safety or security of persons or of property

- Comply with the Interconnected Transmission Owner’s safety, security and work rules, environmental guidelines and training requirements applicable to the area(s) where construction activity is occurring, and
- Submit to the Interconnected Transmission Owner and PJM initial drawings, certified by a registered professional engineer, of the Transmission Owner Interconnection Facilities that the Interconnection Customer/Developer arranges to build under the Option to Build.

Note:
 Further information on all terms and conditions to be incorporated under the Option to Build may be found in Part VI, Section 3.2.3 in App. P, App. 2 – formerly Part IV, Subpart F at 83.2.3 of the PJM Tariff, available in the library section of PJM’s web site.

4.2.4 Specific Process Flow and Timeline (See Timeline in Attachment A)

Activity	Activity Duration	Cumulative Duration
Generation and/or Transmission Interconnection Customer (IC) submits an initial Interconnection Request in the form of an executed Generation and/or Transmission Interconnection Feasibility Study Agreement to PJM with all required information including evidence of ownership interest and a deposit to be used for the Interconnection Studies. PJM informs the affected Interconnected Transmission Owner(s) (ITOs) upon receipt of each Generation and/or Transmission Interconnection Request.	Requests received in 2 cycles per year ending on March 31 and September 30.	Up to 182 days (may be accelerated for small resource projects of 20 MW or less)
PJM conducts Generation and/or Transmission Interconnection Feasibility Study in coordination with each affected ITO. Complete studies in 2 cycles per year (complete by March 31 st and September 30 th)	Up to 92 day window, after 30 day modeling period	Up to 304 days
PJM responds to the IC with the Generation and/or Transmission Interconnection Feasibility Study Agreement results, tenders a System Impact Study Agreement to the IC, provides notification to the affected ITOs and posts the results of the Generation and/or Transmission Interconnection Feasibility Study on the PJM web site.		
IC determines response to the Generation and/or Transmission Interconnection Feasibility Study results.	Up to 30 days	Up to 334 days
IC submits an executed System Impact Study Agreement (with proof of application for an air permit if required for a generator installation) and deposit.		



Activity	Activity Duration	Cumulative Duration
<p>PJM conducts the System Impact Study, in coordination with any affected ITOs, during the next designated cycle and completes the Study within 120 days of commencement.</p> <p>Commence studies in 2 cycles per year (commence by June 1 and December 1)</p>	Up to 120 days for study, after 60 day modeling period	Up to 514 days
<p>PJM advises the IC of the System Impact Study Agreement results, tenders a Facilities Study Agreement to the IC/D, provides notification to the affected ITOs and posts the results of the System Impact Study on the PJM web site.</p>		
<p>IC determines response to the System Impact Study results.</p>	Up to 30 days	Up to 544 days
<p>IC submits an executed Generation and/or Transmission Interconnection Facility Study Agreement with a deposit of \$100,000 or the estimated cost of its project responsibility, whichever is higher (small resources of 20 MW or less pay a deposit in the amount of the estimated cost of the study).</p>		
<p>If one is required, PJM conducts the Generation and/or Transmission Interconnection Facilities Studies, providing good faith estimates of the cost to be charged to each affected IC for the Attachment Facilities, Local Upgrades and Network Upgrades and a "SCHEDULE OF WORK" to complete construction of the facilities and upgrades.</p>	Based on estimate of the time needed	Up to 544 days + time for Facilities Studies
<p>PJM provides the Generation and/or Transmission Interconnection Facilities Studies results to the IC and tenders an Interconnection Service Agreement to each Generation and/or Transmission Interconnection Customer. PJM posts the results of the Generation and/or Transmission Interconnection Facilities Study on the PJM web site. (If the Transmission Interconnection Facilities Study only identifies the need to upgrade existing network facilities, then PJM shall tender an Upgrade Construction Service Agreement to the Transmission Interconnection Customer for execution)</p>		
<p>IC determines response to the Generation and/or Transmission Interconnection Facilities Studies results and the "SCHEDULE OF WORK".</p>		
<p>IC executes and returns tendered Interconnection Service Agreement or Upgrade Construction Service Agreement</p>	Within 60 days	Up to 604 days + F.S.
<p>IC elects Option to Build</p>	Within 37 days following IC	Up to 641 days + F.S.

Activity	Activity Duration	Cumulative Duration
	execution of the Interconnection Service Agreement	
PJM tenders and IC executes and returns Interconnection Construction Service Agreement	Within 45 + 90 days	Up to 739 days + F.S.
If the Generation and/or Transmission Interconnection Customer (IC) selects the Option to Build, the following timeline for various independent activities must be adhered to:		
IC solicits bids from Approved Contractors within 10 days after electing the Option to Build	Within 10 days	Up to 651 days + F.S.
IC submits initial drawings to the Interconnection Transmission Owner (ITO) and PJM - PJM responds within 60 days	Within 60 days	
Constructing entity submits monthly reports	Monthly	
Constructing entity notifies of delays or cost increases – PJM convenes a technical meeting within 15 days	Within 15 days	
Inspection or testing identifies defects – Corrective action is required within 20 days	Within 20 days	
Written notification by ITO is to be provided within 10 days of satisfactory inspection and/or testing and acceptance for energization	Within 10 days	
After successful energization, ITO provides written notice accepting the Interconnection Facilities built by the IC within 5 days	Within 5 days	
IC delivers all documents and filings to the ITO within 30 days of receipt of notice of acceptance	Within 30 days	
After written notice of approval by ITO, the IC makes filings to FERC or other governmental agencies within 30 days	Within 30 days	
After receipt of all regulatory approvals, the IC makes filings to record easements and land rights to be conveyed to the ITO within 20 days	Within 20 days	
Other Timeline requirements:		
Security for Payment - IC shall provide PJM with Security in the amount that is equal to the estimated cost of the ITO Interconnection Facilities that the ITO is responsible for constructing	Within 60 days after the date of IC's receipt of Facilities Study	

Activity	Activity Duration	Cumulative Duration
Submit Invoices		
ITO to PJM	Monthly	
PJM to IC	Monthly	
IC payment to PJM	Within 15 days	
Submit Final Invoice		
ITO to PJM	Within 120 days of project completion	

Cross-References to Other Supporting PJM Documents

4.2.5 PJM Manuals

- PJM Manual for Control Center Requirements (M-1)
- PJM Manual for Transmission Service Request (M-2)
- PJM Manual for Transmission Operations (M-3)
- PJM Manual for Rules and Procedures for Determination of Generating Capability (M-21)

4.2.6 PJM Tariff – Part VI (Interconnections with the Transmission System)

- Subpart A – Generation Interconnection Procedures
- Subpart B – Transmission Interconnection Procedures (Consolidated with Subpart A)
- Subpart C – (Reserved)
- Subpart D – Interconnection Rights (Moved to Subpart C in Part VI)
- Subpart E – Standard Terms and Conditions for Interconnection (Tariff at Part VI, title moved to App. 2 of Att. O. Subpart E – deleted.)
- Subpart F – Standard Construction Terms and Conditions (Tariff at Part VI, title moved to Att. P, App. 2. Subpart F – deleted.)
- Subpart G – Small Generation Interconnection Procedure
- Attachment N-3 – Form of Optional Interconnection Study Agreement
- Attachment O – Form of Interconnection Service Agreement
- Attachment O-1 – Form of Interim Interconnection Service Agreement
- Attachment P – Form of Construction Service Agreement
- Attachment S – Form of Transmission Interconnection Feasibility Study Agreement

4.2.7 PJM Operating Agreement

- Schedule 6 – Regional Transmission Expansion Planning Protocol

4.3 Wholesale Market Participant Agreement (WMPA)

Developers interconnecting to non-FERC jurisdictional facilities who intend on participating in the PJM wholesale market will receive a three party agreement known as a WMPA. The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

4.4 Other Agreements

4.4.1 Station Power

All electric generation facilities consume some electric energy, generally referred to as “station power” in their operations. Station power requirements can include, for example, energy used for re-starting generators after they have been shut down for maintenance or other reasons; for emissions control and related monitoring equipment; for pumping and treating cooling water; for fuel handling equipment; and for lighting, heating and air conditioning of plant control rooms and offices.

Station power is defined as energy consumed in the PJM control area by a generating facility or by equipment or facilities located at the site of a generation facility and used in the operation, maintenance, or repair of the generation facility, regardless of whether the facility is operating when the energy is consumed.

Generators may obtain station service from a local utility under retail tariffs or service agreements. Every generator in PJM's control area remains free (consistent with FERC policy) to purchase any or all of its station power from any seller connected to the grid.

Make certain your contracts or business arrangements for obtaining Station Power are in place before beginning generator operations.

Section 5: Additional Generator Requirements

In this section you will find:

- The definition of Behind the Meter Generation and requirements related to such projects,
- Generator power factor requirements, and
- Wind or Non-Synchronous generator requirements.

5.1 Behind the Meter Generation

Behind the Meter Generation (BtMG) is the output from generation that offsets load and does not and cannot participate in the wholesale market. Thus, in order to be considered BtMG, power claimed as BtMG must deliver energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM).

Generation claimed as BtMG cannot participate in the PJM Capacity or energy market. Even if partial BtMG is proposed, the portion claimed as BtMG must always stay behind the meter unless and until the generator takes the steps required to have the generation participate in the wholesale markets.

Behind the Meter Generation cannot 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 the generating unit(s) that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market. Behind the Meter Generation rules permit load serving entities in PJM to net operating Behind the Meter Generation against load in the calculation of charges for energy, capacity, transmission service, ancillary services and PJM administrative fees. This total netting approach is intended to encourage the use of Behind the Meter Generation during times of scarcity and high prices, thus increasing the opportunity for load to compete in PJM markets.

A professional engineer stamped one-line configuration must be provided to show the relationship between equipment that prevents behind the meter power flow to the system, past the Point of Interconnection meter (in the case of Non-Retail BtMG, equipment must prevent BTMG power flow onto the Transmission System). Additionally, the affected entity must be aware and have performed the necessary studies to assure adequate system capabilities and protections are in place for the receipt of the power.

5.1.1 BtMG Interconnection Requests

Any Behind the Meter Generation that desires to be designated, in whole or in part, as a Capacity Resource or Energy Resource must submit a Generation Interconnection Request. (Tariff at Part VI, in Section 36.1.01 – formerly Subpart A at 36.1A, in Part IV)

5.1.2 BtMG Metering

Behind the meter generation consisting of one or more generating units individually rated at ten megawatts or greater or that otherwise have been identified by PJM as requiring metering for operational security reasons must have both revenue quality metering and telemetry equipment

for operational security purposes. Behind the meter generation consisting of multiple generating units that are individually rated less than ten megawatts but together total more than ten megawatts at a single site and are identified by PJM as requiring revenue quality metering and telemetry equipment may meet these metering requirements by being metered as a single unit. (Operating Agreement, Section 14.5)

5.1.3 BtMG Effects on Market Operations

Market Buyers shall be charged for all load and associated ancillary services based on the Market Buyer's total load (net of operating Behind the Meter Generation, but not to be less than zero.) (Operating Agreement, Schedule 1)

5.1.4 Non-Retail BtMG

Non-Retail BtMG refers to state interconnected generators that reduce the load of an electric distribution company, electric co-operative or municipality utility. The Generation Owner in this case does not request this status. The request for Non-Retail BTMG status must come for the affected electric distribution utility, electric cooperative or municipal utility, whose transmission served load requirements are being impacted.

Non-Retail BtMG rules permit load serving entities in PJM to net operating BtMG against load in the calculation of charges for energy, capacity, transmission service, ancillary services and PJM administrative fees. This total netting approach is intended to encourage the use of BtMG during times of scarcity and high prices, thus increasing the opportunity for load to compete in PJM markets.

5.2 Generator Power Factor Requirements

Except as PJM may determine otherwise for small generation resources of 20 MW or less, all generators interconnected with the PJM System shall be designed to maintain a composite power delivery at continuous rated power output and reactive capability, at the generator terminal, corresponding to the power factor requirements stated in the Tariff. (Tariff at Part VI, Att. O, App. 2, Section 4.7.1 – formerly 54.7.1 in Part IV)

5.2.1 Application of Power Factor Requirements to Increases of Existing Generation

Tariff provisions require existing generators to be designed to operate at a specified leading and lagging power factor as measured at the generator terminals.

- Power Factor requirements also apply to capacity or energy increases to existing generation. (Tariff at Part VI, Att. O, App. 2, Section 4.7.1.2)

Increases to existing generators must be designed to maintain the grandfathered Mvar capability for the existing and pre-upgraded gross generator output capability and the Section 4.7.1.2 power factor requirement for all incremental MW increases.

Grandfathered Mvar capability will be determined using the following methodology and considerations.

- If an agreement exists and contains a reference to required Mvar capability, the methodology in the agreement will determine the grandfathered Mvar capability.

- Consideration will be given to the potential interpretations of the language in the agreement. Non-standard or vague terms and conditions will be discussed by PJM and the parties named in the agreement.
- If no agreement exists or there is no reference to required Mvar capability in an existing agreement, PJM will use alternate methods to determine the grandfathered Mvar capability of the machine.
- Examples of potential alternate methods that may be used at PJM's discretion.
- Use of the D-Curve provided by the manufacturer and is on file with PJM.
- Review of the data with the GO and provide an opportunity for the GO provide additional analytical evidence as to the actual Mvar capability, if different from the manufacturer design data.
- Consideration of available test data with acknowledgement that tests are not always performed under ideal conditions and the system may limit the capability during testing. Input from the GO will also be considered as part of the evaluation by PJM.
- Consideration of historical operational data.

Attachment H to this Manual 14A details a process, adhering to the requirements of the PJM Tariff, to mitigate the reactive deficiency arising when an increase of capacity or energy to an existing generator results in the generator not being able to meet the PJM power factor requirements for the existing and/or incremental capacity or energy.

5.3 Wind or Non-Synchronous Generation Projects

Because of the intermittent nature of wind-power and other non-synchronous generation, a specific procedure is required to determine an appropriate capacity value for these facilities.

5.3.1 Wind or Non-Synchronous Generation Capacity Credit Rules

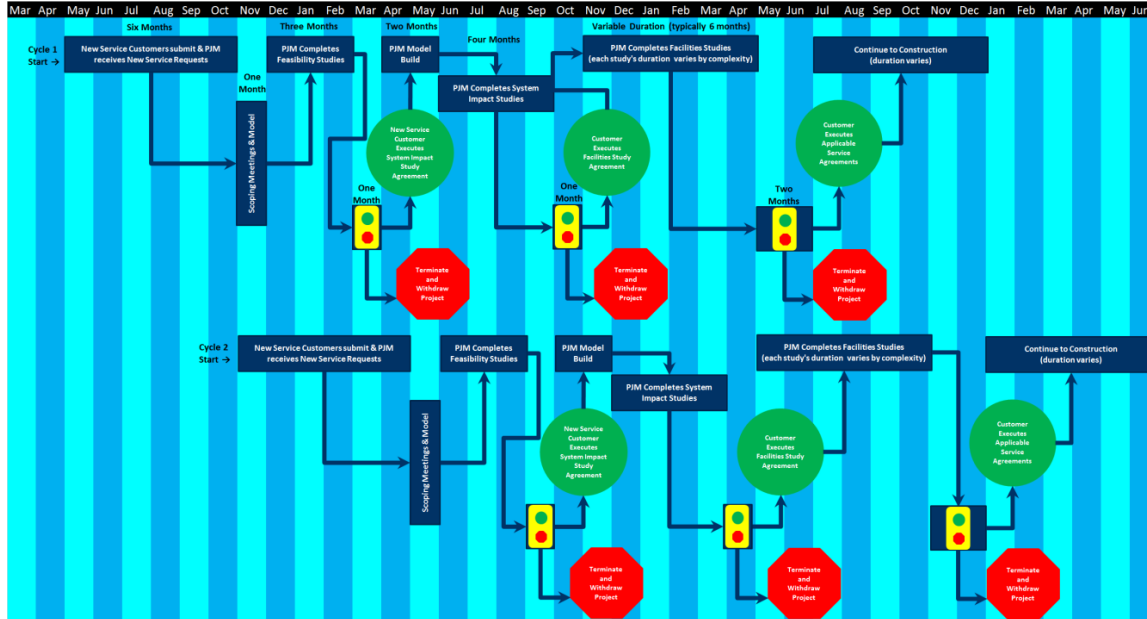
PJM business rules allow for wind or non-synchronous generation projects to qualify for Capacity Resource status. Refer to PJM Manual 21 – “Rules and Procedures for Determination of Generating Capability” for details of PJM procedures for calculating Capacity Credits for these facilities.

5.3.2 Wind or Non-Synchronous Generation—Specific Technical Requirements

Without exception, all Customer Facilities will be subject to the provisions of the PJM Tariff at **Part VI, in Section 4.7.2 and Section 4.7.3 in Att. O, App. 2 – formerly 54.7.2 and 54.7.3 in Part IV**, which describes real-time obligations to supply reactive power and the consequences of deviations from voltage schedules and/or reactive power schedules.

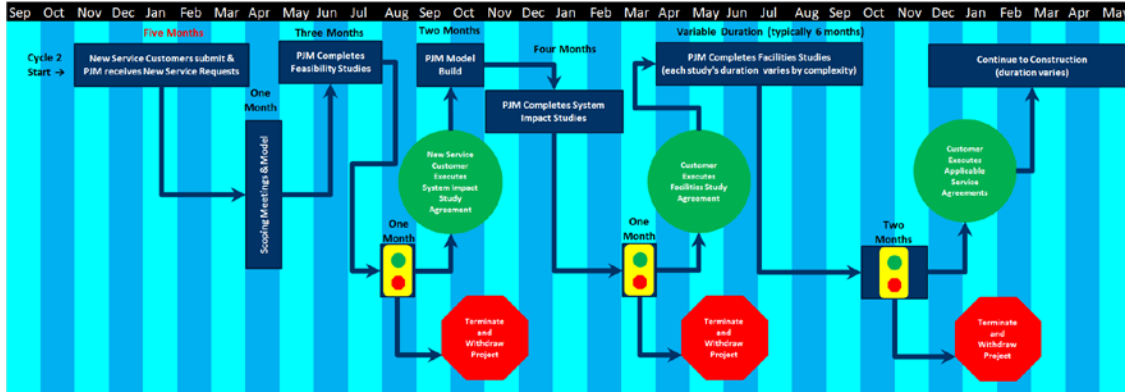
Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow Diagram

Valid through October 31, 2016



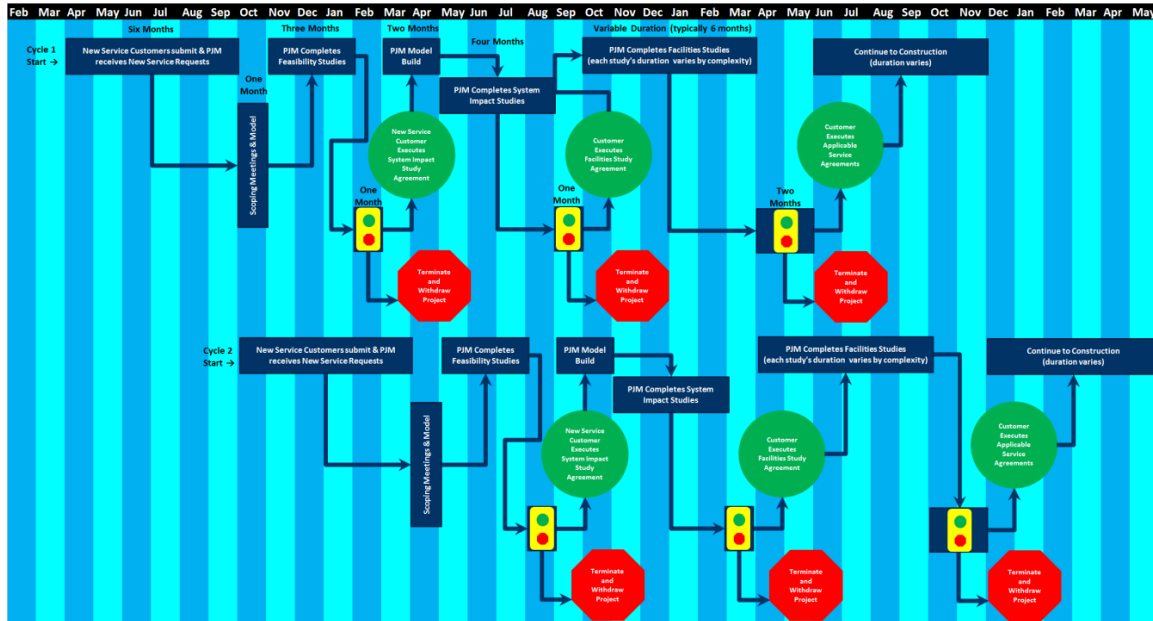
Attachment A-1: PJM Generation and Transmission Interconnection Planning Process Flow Diagram

Transitional Period: November 1, 2016 through March 31, 2017



Attachment A-2: PJM Generation and Transmission Interconnection Planning Process Flow Diagram

Valid: April 1, 2017 forward



Attachment B: PJM Request Cost Allocation Procedures

B.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer New Service Requests, baseline transmission reliability upgrades and market efficiency upgrades. The cost allocation procedures used by PJM to allocate costs due to requests are described below. Manual 14B addresses baseline-driven upgrade cost allocation procedures.

B.2 Scope

The RTEP encompasses two types of enhancements: Network Upgrades and Direct Connection Attachment Facilities. Network Upgrades can be required in order to accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. The PJM Cost Allocation Procedures are presented in two parts: “PJM Generation and Transmission Interconnection Cost Allocation Methodologies” discusses the cost allocation methodology for projects required for generator and transmission interconnections, below and: “Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades” discusses the cost allocation process for baseline transmission reliability and market efficiency upgrade project requirements in Manual 14B. New Service Customers, other than those proposing Merchant Network Upgrades, may participate in Multi-Driver Approach projects identified by PJM. Further information is provided in Manual 14B.

The results of the System Impact Studies reveal Direct Connection Attachment Facilities required for new generation to “get to the bus”, Local and Network Upgrades to mitigate any “network impact” effects which the addition of such new generation or new transmission facilities may have on the power system itself.

- Each respective generator or transmission project bears the cost responsibility for Direct Connection Attachment facilities required for interconnection.
- The cost responsibility for Local and Network Upgrades identified through System Impact Study analysis is allocated among parties according to the following:
- For Local and Network Upgrades which are required due to the overloads associated with the System Impact Studies of an individual New Services Queue, the cost of the Local and Network Upgrades will be allocated according to the order of the New Service Requests in the New Services Queue and the MW contribution of each individual New Service Request for those projects which cause or contribute to the need for the Local or Network Upgrades. The Load Flow Cost Allocation methods discussed in this manual, including cutoffs, still apply to the individual projects.

B.2.1 Definitions

- New Service Queue Close Date – The date on which a New Service Queue ends. Currently, in the PJM Tariff, the New Service Queue Close Dates are March 31st and September 30th.

- New Service Customer – The responsible party for a generator, merchant transmission, or other transmission upgrade project that is in the PJM New Service Queue.
- Queue Date – The date on which PJM receives a valid New Service Request from a New Service Customer.

B.3 PJM Generation and Transmission Interconnection Cost Allocation Methodologies

The cost allocation procedure will continue to be evaluated and modified, if required, as the interconnection process proceeds.

B.3.1 Load Flow Cost Allocation Method

New Service Customer requests are studied as a single study for all active projects in an individual New Services Queue. Network Upgrades are identified to maintain system reliability.

Individual Local & Network Upgrades which cost less than \$5,000,000

All New Service Customers with active New Service Requests in an individual New Services Queue will be allocated a cost for these Network Upgrades based upon the following criteria:

- The first New Service Customer to cause the facility identified in the study which exceeds 100% loading of the applicable rating and develops the need for the Network Upgrade will in all cases have some cost allocation.
- Contingent to the individual New Service Request contributing MW impact being greater than 5 MW AND greater than 1% of the applicable line rating OR (if its Distribution Factor (DFAX) on the facility is greater than 5% AND its MW impact on the facility's rating is greater than 3%), the contribution of a New Service Customer is determined by the voltage level of the facility that it impacts:
- For a transmission facility whose rated voltage level is below 500 kV, a New Service Customer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
- For a transmission facility whose rated voltage level is 500 kV or above, a New Service Customer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.
- For New Service Requests involving studies for Long Term Firm Transmission Service seeking to import power to PJM, or which otherwise have their source of power outside PJM, the New Service Customer will have some cost allocation towards upgrades associated with all PJM facilities, if its Distribution Factor (DFAX) on the facility is greater than 3% OR if its MW impact on the facility's rating is greater than 3%.
- Allocation of costs to New Service Customers for a Network Upgrade which has a cost of less than \$5,000,000 will not occur outside of the New Services Queue in which the need for the Network Upgrade was identified
- Allocation of costs to New Service Customers for a Network Upgrade which has a cost of less than \$5,000,000 will be based on the total MW impact on the facility requiring a Network Upgrade as determined in the System Impact Study

Individual Local & Network Upgrades which cost \$5,000,000 or greater

All New Service Customers after and including the New Service Customer under study, that contribute to the need for the Network Upgrade are identified and their MW impact on the need for the Network Upgrade is determined. The MW impact will be based on the condition that causes the need for a Network Upgrade.

- The first New Service Customer to cause the need for the Network Upgrade will in all cases have some cost allocation. The cost allocation for this New Service Customer will only consider the loading above the facility's capability.
- Contingent to the contributing MW impact being greater than 5 MW AND greater than 1% of the applicable line rating, the contribution of a New Service Customer following the first New Service Customer to cause the need for the Network Upgrade is determined by the voltage level of the facility that it impacts:
- For a transmission facility whose rated voltage level is below 500 kV, a New Service Customer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
- For a transmission facility whose rated voltage level is 500 kV or above, a New Service Customer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.
- For New Service Requests involving studies for Long Term Firm Transmission Service seeking to import power to PJM, or which otherwise have their source of power outside PJM, the New Service Customer will have some cost allocation towards upgrades associated with all PJM facilities, if its Distribution Factor (DFAX) on the facility is greater than 3% OR if its MW impact on the facility's rating is greater than 3%.
- New Service Customers will be assigned costs in proportion to their contributing MW impacts.

For purposes of allocation of Network Upgrade costs to future Queue, a New Service Customer will be responsible for allocated costs, within previously stated cost allocation guidelines, if their New Service Queue Close Date occurs less than 5 years following the execution of the first Interconnection Service Agreement or Upgrade Construction Service Agreement which identifies the need for this Network Upgrade.

No depreciation of the "as-built" Network Upgrade cost will be used when allocating costs between New Service Customers.

Cost allocation for the engineering design of Network Upgrades will terminate based on the completion of the applicable Facilities Study.

A complete list of Distribution Factors for all PJM modeled substations will be developed during System Impact Studies for each identified Network Upgrade. This Distribution Factor list will be used for all cost allocation pertaining to the identified Network Upgrade.

B.3.2 Short Circuit Cost Allocation Method

All New Service Customer projects are studied in queue order.

A New Service Customer will have some cost allocation if the customer's contributing fault current impact on the circuit breaker's applicable interrupting rating is greater than 3% or if it results in a greater than 3% increase in fault current at the substation. The first _____

New Service Customer to cause the need for the Network Upgrade will in all cases have some cost allocation.

A New Service Customer will be assigned costs in proportion to its fault level contribution or the fault level increase as a result of the inclusion of a new Network Upgrade required by that New Service Customer.

For Queue D and thereafter, the first New Service Customer to cause the need for a Network Upgrade due to increased fault current will in all cases have some cost allocation. The cost allocation for this New Service Customer will only consider the loading above the equipment's capability.

For purposes of allocation of Network Upgrade costs to future Queue, a New Service Customer will be responsible for allocated costs, within previously stated cost allocation guidelines, if their New Service Queue Close Date occurs less than 5 years following the execution of the first Interconnection Service Agreement, or Upgrade Construction Service Agreement which identifies the need for this Network Upgrade.

If during the course of a short circuit study it is determined that a load flow (or stability) reinforcement subsequently causes breaker(s) to exceed their applicable rating, the cost of breakers identified in this case will be allocated based on the load flow (or stability) cost allocation rules associated with the load flow (or stability) reinforcement as these breaker(s) are considered a part of the load flow (or stability) reinforcement. The contributing fault current from the modeling of the reinforcement is recorded in the event that another queue request does not require the load flow reinforcement, but instead, adds fault current in excess of the normal short circuit threshold of 3% to a breaker. See below for an example of cost allocation for load flow (or stability) driven circuit breaker replacements.

Example of cost allocation for circuit breaker replacement with thermal (or stability) upgrade driver (or contributor) to the fault current:

<u>Queue Position</u>	<u>MW Contribution</u>	<u>Thermal upgrade cost allocation</u>
<u>XX-001</u>	<u>50</u>	<u>50%</u>
<u>XX-002</u>	<u>30</u>	<u>30%</u>
<u>XX-003</u>	<u>20</u>	<u>20%</u>

Modeling of the Thermal upgrade in the short circuit study case results in the contribution of 10kA to a breaker and causes the breaker to be overstressed.

<u>Driver</u>	<u>Fault contribution (kA)</u>	<u>Short Circuit + Thermal Cost Allocation impacts (kA)</u>	<u>Total Cost allocation for Short Circuit contribution (kA)</u>
<u>Thermal upgrade</u>	<u>10</u>	<u>N/A</u>	<u>N/A</u>
<u>XX-001</u>	<u>2</u>	<u>2+10*0.5 (2 is fault contribution from project generator(s), 10 is fault contribution from</u>	<u>2+5=7</u>

		reinforcement, 0.5 = 50% cost allocation per thermal analysis)	
XX-002	4	4+10*0.3 (4 is fault contribution from project generator(s), 10 is fault contribution from reinforcement, 0.3 = 30% cost allocation per thermal analysis)	4+3=7
XX-003	1	1+10*0.2(1 is fault contribution from project generator(s), 10 is fault contribution from reinforcement, 0.2 = 20% cost allocation per thermal analysis)	1+2=3
XX-004 (does not require thermal upgrade)	3	3+0	3

The total cost allocation for short circuit contribution is the basis for the determination of the cost allocation towards the breaker upgrade costs. If a breaker replacement cost \$1M, and based on the contributions listed above, the cost allocation for the breaker upgrade is below.

Driver	Total Cost Allocation for Short Circuit contribution (kA)	Cost Allocation
XX-001	2+5=7	$(7/(7+7+3+3))*\$1M=\$350K$
XX-002	4+3=7	$(7/(7+7+3+3))*\$1M=\$350K$
XX-003	1+2=3	$(3/(7+7+3+3))*\$1M=\$150K$
XX-004 (does not require thermal upgrade)	3	$(3/(7+7+3+3))*\$1M=\$150K$

No depreciation of the “as-built” Network Upgrade cost will be used when allocating costs between New Service Customers.

Cost allocation for the engineering design of Network Upgrades will terminate based on the completion of the applicable Facilities Study.

PJM will consider application of an individual component cost vs. an aggregate cost when determining the cost allocation window.

B.3.3 Cost Allocation Method for Generator and/or Generator Step Up (GSU) Changes

The generator and generator step up transformer (GSU) characteristics provided by the Developer prior to the initiation of the System Impact Studies for a given queue will be used for all cost allocation during the System Impact Study phase. If a Developer changes the generator or GSU characteristics after initiation of the System Impact Studies, any additional system problems and any resulting reinforcements will be assigned completely to the Generation Interconnection project that made the changes. Future queued generation may share some cost allocation based on when the generator or GSU changes were provided to PJM.

- Example 1: Impact studies for Queue Z started on May 10, 2010. Five 230 kV breakers at substation Alpha were required to be replaced due to several projects in Queue Z. Project Z2 which had some cost allocation for the five 230 kV breakers provided new GSU data on May 25, 2010. The new GSU has higher impedance. If all five breakers are determined to still be needed with the new GSU impedance, the original cost allocation will not change. If only four breakers are now required, the cost allocation for the four breakers that are still required will not change.
- Example 2: Impact studies for Queue Z started on May 10, 2010. Five 230 kV breakers at substation Alpha were identified to be replaced due to several projects in Queue Z. Project Z2 which had some cost allocation for the five 230 kV breakers provided new GSU data on May 25, 2010. The new GSU has a lower impedance. Now six 230 kV breakers at substation Alpha need to be replaced. Project Z2 will be assigned 100% of the cost for the sixth breaker and the cost allocation for the original five 230 kV breakers will not change.
- The rules concerning generator and GSU changes will be applied to generators in Queue B and thereafter.

B.3.4 Generation Project Excess MW Capabilities

The machine data provided by generation projects often contain MW capabilities that exceed the queued Capacity Interconnection Rights for that project. These additional MWs may result in a system that does not meet ReliabilityFirst Criteria for certain contingencies not “observed” in operations such as bus faults, and ReliabilityFirst Standard IIC contingencies (tower line, line fault with stuck breaker, faulted breaker). Consequently, after all generation projects in a given queue have executed a Generation Interconnection Facility Study Agreement, the PJM system will be evaluated using the MW capabilities provided by the Developers to determine whether there are any bus fault or ReliabilityFirst Standard IIC violations. Any additional system problems will need to be rectified through either limiting the generator capability via hardware or upgrade of the Transmission System to eliminate the violation.

- The rules concerning excess project MW capabilities will be applied to generators in Queue B and thereafter.

B.3.5 Stability	Cost	Allocation	Method
All New Service Customer projects will be studied in queue order as established under the PJM Tariff.			

If a stability constraint is identified during the study of a New Service Request, the New Service Customer(s) which contributes to the need for that reinforcement will be allocated a portion of the costs for the required Network Upgrade to eliminate the stability constraint.

A New Service Customer will be assigned costs in proportion to the MW contribution towards the need for the Network Upgrade.

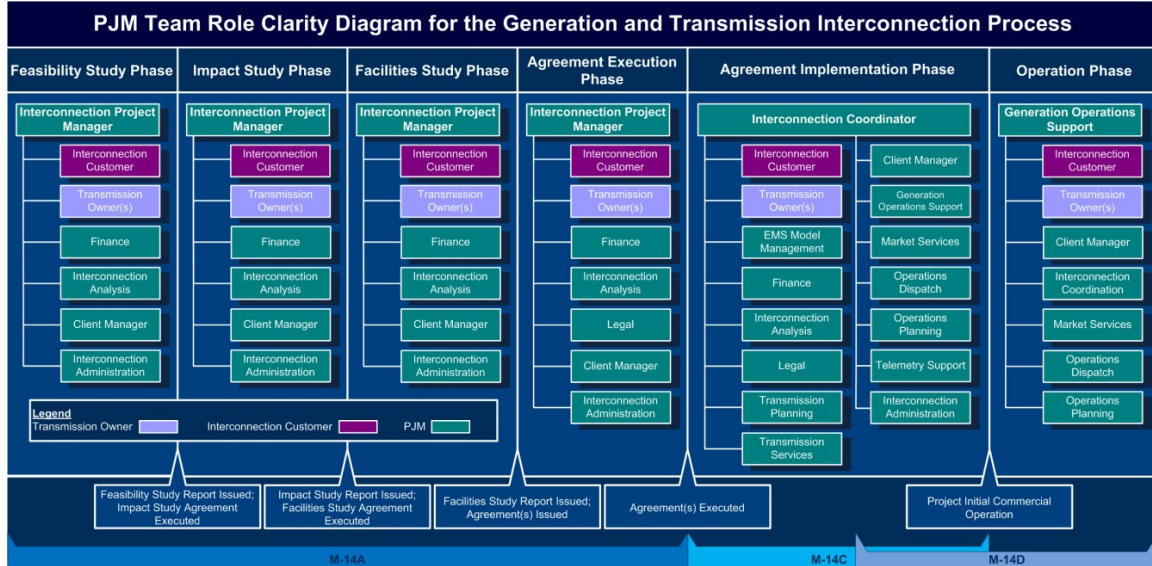
The determination of the MW contribution for each New Service Customer is the margin between its MFO, or total capabilities, and the MW quantity at which the impact from the request ceases to cause the need for the Network Upgrade. A New Service Request with any impact which would cause system instability without a necessary Network Upgrade, will have its requested MW quantity reduced in steps to estimate the stability limit where the disturbances in the stability study would not cause any need for system reinforcement through the implementation of a Network Upgrade. In each step of the MW reduction, the New Service Request's MW quantity is reduced by 50MW or 10% of its MFO, or total capability, whichever is larger, to examine if system stability is maintained at this reduced MW value. The MW contribution for stability cost allocation for the individual New Service Customer is the difference between the MFO, or total capability, and the MW quantity at which the system stability is restored without the need for the Network Upgrade.

A New Service Customer will be responsible for allocated costs, within previously stated cost allocation guidelines, if their New Service Queue Closing Date occurs less than 5 years following the execution of the first Interconnection Service Agreement, or Upgrade Construction Service Agreement, which identifies the need for this Network Upgrade.

No depreciation of the "as-built" Network Upgrade cost will be used when allocating costs between New Service Customers.

Cost allocation for the engineering design of Network Upgrades will terminate based on the completion of the applicable Facilities Study.

Attachment C: PJM Generation and Transmission Interconnection Planning Team Role Clarity Diagram



Attachment D: General Description of Facilities Study Procedure

Introduction

A Facilities Study is an engineering study conducted by the Transmission Provider to describe the modifications required to the Transmission Provider's (PJM's) Transmission System to provide the requested Generator and/or Transmission Interconnection Service. PJM may contract with consultants, including the Interconnected Transmission Owner (ITO) and any other affected Transmission Owners (TO), to obtain services or expertise.

The purpose of the Facilities Study is to provide, *commensurate with any mutually agreed parameters regarding the scope and degree of specificity described in Schedule A of the Facilities Study Agreement, conceptual (or preliminary) design, and, as appropriate, detailed design, plus cost estimates and project schedules*, to implement the conclusions of the System Impact Study regarding the Attachment Facilities, Network Upgrades and Local Upgrades (i.e. upgrades related to non-Tariff designated facilities) necessary to accommodate the Interconnection Customer's Interconnection Request(s).

Examples of typical Facilities Study deliverables are preliminary single line diagrams and general arrangement drawings for substation work, and delineation of proposed study area and proposed conductor and structure designs for transmission line work. Remaining detailed design activities would be completed during the construction phase of the project.

The Facilities Study Agreement (FSA) between the Interconnection Customer/Developer ("the Customer") and PJM will identify the scope of facility additions and upgrades to be included in this study. The FSA may also include milestones for completion of the Customer's facility study, where such work completion is critical to PJM's Facilities Study schedule.

General Guidelines

Facilities Study work will be initiated by a Kickoff meeting attended by the ITO, affected TO(s), the Customer, and PJM. The following types of information will be communicated at the Kickoff meeting:

The Customer shall provide a schedule for construction and anticipated commercial operation of the Customer's facilities. The Customer's schedule shall include the date when backfeed power is required, and the dates for anticipated test and commercial operation of each generating unit or transmission facility.

Interconnection specific information, including but not limited to:

- a one-line diagram showing the location of the Point of Interconnection,
- a customer facility location/site plan,
- a list of Interconnection Facilities and Ownership,
- if applicable, a list and ownership of Merchant Network Upgrades,
- a one-line diagram showing location and ownership of Metering Equipment,
- the Applicable Technical standards that apply to the Customer Facility and the Interconnection Facilities, and

- the Maximum Facility Output and/or the Nominal Rated Capability of the Customer Facility.

The scope of the Customer's, PJM's, ITO's and other affected TO's facilities study work will be delineated, and a schedule for completion of Facilities Study elements will be established. The scheduled completion of the Facilities Study shall not extend beyond the time estimate provided by the FSA.

A tentative schedule for Status meetings will be established. Status meetings may be necessary in those instances where information about one or more completed elements of the Facilities Study may be critical to the Customer's decision to continue the Facilities Study.

Results of PJM's Facilities Study shall be reported to the Customer in the form of a Facilities Study Report ("the Report"). The Report must contain a good-faith estimate of costs and construction schedules for each new or upgraded facility. In addition, the Report must contain sufficient detail about the engineering design of each facility. This will provide the Customer with information necessary to perform due diligence on the work to be performed by PJM, the ITO and other affected TO(s). The Report, less confidential or sensitive material, will be integrated with other Reports from other Transmission Owners (if applicable), and will also be posted on PJM's Web site.

All Report materials must be capable of being included in an MS Word document, formatted for 8 ½ in. by 11 in. printing. The Report shall identify the Customer's project by the queue number assigned to the project on PJM's web site. For example: "Project A57".

Facilities Study reports submitted to PJM shall consist of two primary sections:

Transmission Owner Facilities Study Summary

Transmission Owner Facilities Study Results

1. Transmission Owner Facilities Study Summary

- Description of Project
 - Provide a general description of the Customer's project that resulted in the need for the addition and/or upgrade of facilities. The information under the General paragraph of the System Impact Study Report shall be used as the basis for the Project description. Changes to the information provided in the System Impact Study shall be noted and recorded.
- Amendments to the System Impact Study data or System Impact Study Results
 - In general, significant changes to a Customer's project will not be allowed within the existing queue position for the Customer's interconnection request. However, changes to generator data or generator step-up transformer data, withdrawal of an interconnection Request with a lower queue number, or other changes allowed by PJM's business rules can cause the need to re-evaluate the Customer's System Impact Study and amend the results.
- Interconnection Customer's Submitted Milestone Schedule
 - The Customer's submitted project schedule will be documented in this portion of the Report. This schedule will be used as the basis for developing the schedules for

- the purchase of equipment and the construction of facilities upgrades and additions contained in PJM's scope of Facilities Study work.
- Scope of Customer's Work
 - In general, the scope of the Customer's facility study work will be limited to the direct connection facilities up to, but not including, the point of interconnection to a TO's facilities. The Customer's facilities study results will be included in the Report to the extent required to adequately support PJM's Facility Study results.
 - Description of Facilities Included in the Facilities Study
 - A general description of transmission lines, substations, protection systems, etc. that are included in the Facilities Study Report.
 - Total Costs of Transmission Owner Facilities included in Facilities Study
 - A summary level statement indicating the total estimated costs for both Attachment Facilities and Network Upgrades included in the Facilities Study.
 - Summary of Milestone Schedules for Completion of Work Included in Facilities Study:
 - Summary level schedule for detailed design, material & equipment procurement, and construction & testing for Attachment Facilities and Network Upgrades included in Facilities Study. This section should include a statement of comparison (i.e. alignment or misalignment) with Interconnection Customer's milestone schedule.

2. Transmission Owner Facilities Study Results

- Transmission Lines – New
 - The Report shall include a “purpose and necessity” statement as well as a general description of alternative routes, terminal points, geographic description of terrain traversed by the new line, right-of-way width by segment, potential use of common corridors where such use exists, and a description of the permits required.
 - The following information must also be described; design criteria (may be summarized and reference published documents), nominal voltage rating, physical characteristics (overhead, underground, single circuit, double circuit, AC, DC, etc), line MVA normal and emergency rating, BIL, line impedance (positive and zero sequence), line and shield conductor type and size, type of support structure, and grounding design.
 - Applicable Transmission Owner Technical Standards should be referenced in the Report.
- A specific reference to “PJM Transmission and Substation Design Subcommittee Technical Requirements” (note: upon approval) must be made for new or upgraded facilities.
 - Material specifications and a materials list, if available, may be included in the report or referenced.
 - All permit requirements must be identified.

- o Attachments required: geographic map with Customer facility location/site plan, with proposed transmission line study area superimposed.
- o Attachments optional: drawings for typical structure types.
- Transmission Line – Upgrades
 - o As applicable, the same information, as listed above for “Transmission Lines – New”, distinguishing between existing and new equipment.
 - o Attachments: As applicable, same as above for “Transmission Lines – New”.
- New Substation/Switchyard Facilities
 - o The Report shall include a “purpose and necessity” statement, a general description of the functional station design and layout, proposed location, and a description of the potential permits required.
 - o Also included shall be a description of the structural design, the electrical design including rating specifications and rating for all major electrical equipment (e.g. power transformers, circuit breakers, switches, instrument transformers, capacitor voltage transformers, etc.), and the protective relaying, communications, metering, and instrumentation requirements.
 - o Applicable Transmission Owner Technical Standards should be referenced in the Report.
 - o A specific reference to “PJM Transmission and Substation Design Subcommittee Technical Requirements” (note: upon approval) must be made for new or upgraded facilities.
 - o A Specific reference to the “PJM Relay Philosophy and Design Standards” (note: upon approval) must be made for new or upgraded protective relay equipment.
 - o Material specifications and a materials list, if available, may be included in or referenced in the Report.
 - o All permit requirements must be identified.
 - o Attachments required: One-line diagram for each substation / switchyard where facilities are to be added or upgraded. General arrangement diagram showing the physical layout of the new substation facilities.
 - o Optional Attachment: Relay, Instrumentation, and Control one-line diagram.
- Upgrades to Substation / Switchyard Facilities
 - o As applicable, the same information listed above for “New Substation / Switchyard Facilities”, distinguishing between existing and new equipment.
 - o Attachments: As applicable, same as above for “New Substation / Switchyard Facilities”.
- Metering & Communications
 - o General requirements for revenue and telemetry metering, SCADA RTU, and telecommunications, coordinated with PJM requirements.

- Environmental, Real Estate and Permitting Issues
 - o Assessment of environmental impacts related to Attachment Facilities and/or Network Upgrades (i.e. Environmental Impact Study requirements, environmental permitting, sediment & erosion control issues), real estate ownership / easement issues, siting and Right-of Way issues for Transmission Owner side of Point of Interconnection.
- Summary of Results of Study
- Cost Estimates
 - o A table listing construction cost estimates for each new or upgraded facility shall be provided. As applicable, identify and include all taxes and additional charges such as CIAC.
 - o At a minimum, cost estimates shall be included with the following level of detail, along with the total costs (note: keep applicable CIAC tax gross-up amounts separate from total costs). Include both direct and indirect costs in each cost category:
 - o Attachment Facilities:
 - Detailed Design Costs
 - o Material and Equipment Costs
 - Construction and Testing Costs
 - Miscellaneous Costs (i.e., real estate fees, environmental studies, contingencies, project management/oversight – specify details)
 - CIAC Tax Gross-up (if applicable)
 - o Each Network Upgrade:
 - Detailed Design Costs
 - Material and Equipment Costs
 - Construction and Testing Costs
 - Miscellaneous Costs (i.e., real estate fees, environmental studies, project management/oversight, contingencies – specify details)
 - CIAC Tax Gross-up (if applicable)
 - o Additional level of detail for cost estimates shall be provided if indicated in Schedule A of the Facilities Study Agreement.
- Schedules
 - o A milestone schedule, including major milestones (e.g. completion of final design, prepare specifications, solicit bids, construction completion) shall be provided for all facilities within PJM's and the TO's scope of work.
 - o A statement concerning the ability to meet the Customer's scheduled milestones must be included.

- o Additional level of detail for project scheduled shall be provided if indicated in the Facilities Study Agreement.
- Assumptions
 - o A list of assumptions, uncertainties and / or qualifiers that may adversely impact the estimated costs and/or schedules must be identified.
 - o Some examples of items to be detailed in this section are environmental permitting, real estate/easement acquisition, public / customer opposition, equipment availability/ system constraints/time of year limitations, scope definition with respect to accelerated schedule, contractor cost variability.
- Information Required for Interconnection Service Agreement
 - o A table with a cost breakdown for the FERC filing of the Interconnection Service Agreement must be provided. The table shall include the total cost for all facilities to be constructed by the TO. The costs must be itemized in the following categories:
 - Attachment Facilities:
 - Direct Charges Labor
- Direct Charges Material
 - o Indirect Charges Labor
 - o Indirect Charges material
 - o Carrying Charges*
- Network Facilities:
 - o Direct Charges Labor
 - o Direct Charges Material
 - o Indirect Charges Labor
 - o Indirect Charges material
 - o Carrying Charges*
 - * The Carrying Charge Rate must be specified.

Note:

The cost breakdown indicated above is for use in the ISA in accordance with FERC guidelines, and is in addition to the cost breakdown detailed in Section 7.

- The following are definitions for the above cost types:
 - o Direct Costs: These are costs directly associated with the project. These costs need to be separated into “Direct Labor” costs which include the cost of labor to design/build/install the upgrades or facilities, and “Direct Material” costs which include the cost of the physical upgrades and equipment.

- o Indirect Costs: These costs include A&G expenses such as the salary of the payroll clerk.
- o Carrying Charges: These costs are the time value of money associated with the project (i.e., AFUDC). The interest rate must be specified.

Attachment E: Small Generator (10 MW or Less) Technical Requirements and Standards

E.1 Scope

The PJM Small Generator Interconnection Applicable Technical Requirements and Standards (“Small Generator Standards”) shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of 10 MW or less at the point of interconnection.

The Small Generator Standards shall be read and construed as to be consistent with the PJM Tariff (“Tariff”). In the event of any inconsistency between the terms and conditions of the Small Generator Standards and the terms and conditions of the Tariff, the terms of the Tariff shall control. All terms contained in the Small Generator Standards shall be defined as defined by the Tariff. While PJM strives to ensure that the information reflected herein is complete, accurate and reliable, it expressly disclaims any warranty, whether express or implied, as to information contained. Entities relying on the information contained herein do so at their own risk.

E.2 Purpose

To align the applicable technical requirements used within PJM with the IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, and to facilitate the pre-certification of manufactured generation equipment and systems for use within PJM.

E.3 Background and Discussion

Developed by the PJM Small Generator Interconnection Working Group (“SGIWG”), the Small Generation Standards define the uniform technical requirements that each Interconnected Transmission Owner (“ITO”) and Electric Distribution Company (“EDC”) requires for interconnecting to their facilities. The requirements as defined herein will govern for the interconnection of distributed generation 10 MW or less.

ITOs and EDCs may, by mutual agreement, elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein, but may not add requirements to IEEE 1547 other than the exceptions and conditions contained herein. For small generators qualifying for interconnection under state rules, the state-approved technical requirements and procedures shall govern. In the event that a small generator has interconnected under state rules and thereafter elects to participate in any PJM market, such small generator must comply with the terms of PJM's Small Resource Interconnection Procedure Manual and these Small Generation Standards. The small generator must submit a completed Feasibility Study Request (Attachment N of the Tariff) and will be responsible for any subsequent study costs. Additionally, the small generator will be required to execute PJM's three-party Interconnection Service Agreement with PJM and the local Transmission Owner, and to the extent applicable, an Electric Distribution Company, as the case may be.

E.4 General Application Note for Transmission System Interconnections

In its present form IEEE Standard 1547 is primarily intended to address generator interconnections of 10 MVA or less to radial distribution systems. In order to extend the use of IEEE Standard 1547 beyond this scope to include connection to transmission⁵ facilities, it is necessary to clarify the meaning of Section 4.2.1 to assure that system protection requirements are compatible with the established reliability criteria used for those systems.

IEEE Standard 1547 Section 4.2.1 (Area EPS Faults) requires that “the DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.” For transmission Interconnections, this implies that the protection scheme(s) be compatible and coordinate with the Area EPS protection scheme(s) used for the line or substation to which they are interconnected, or be compatible and coordinate with new protection equipment installed due to the connection of the generation to this facility.

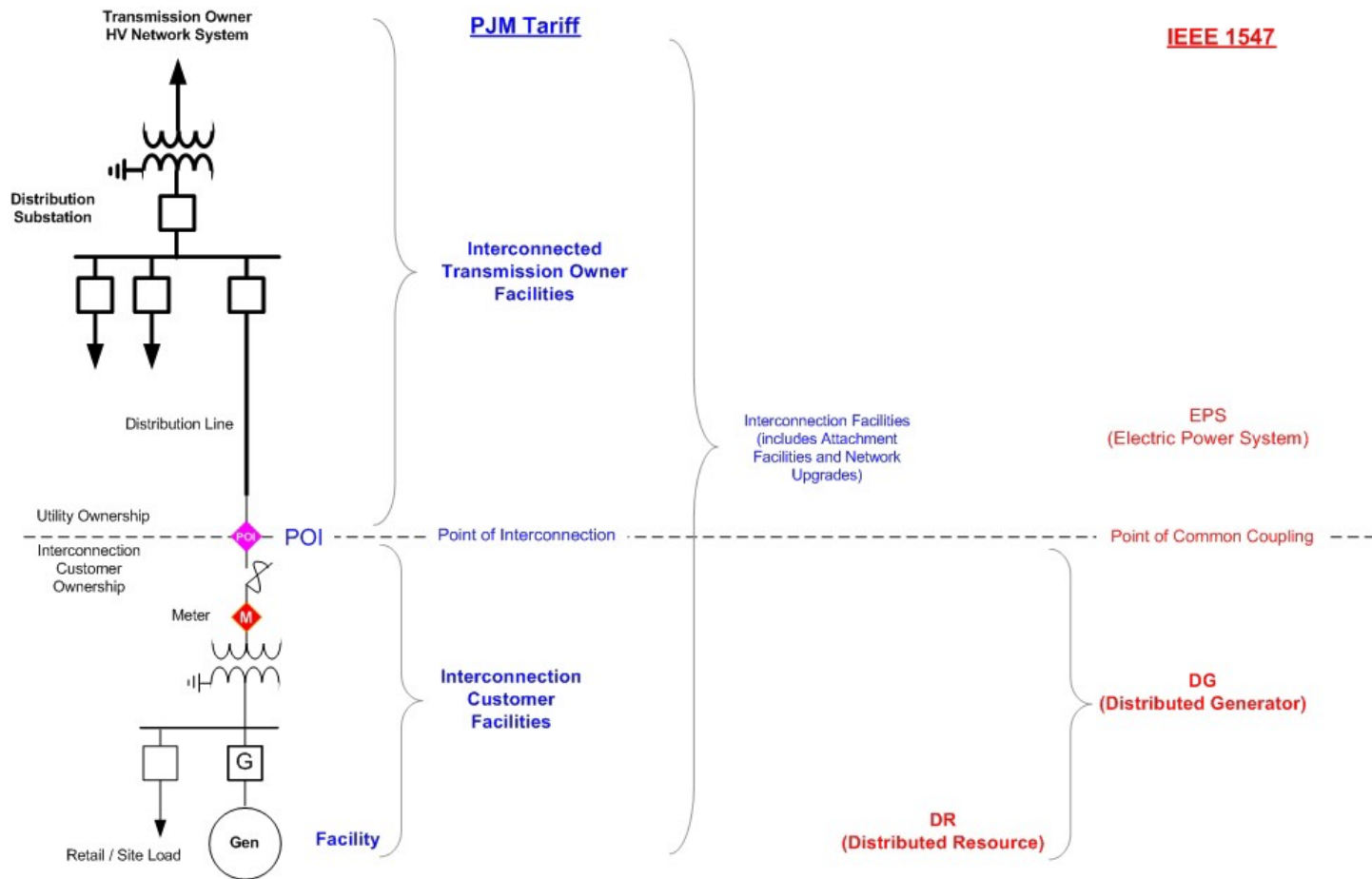
E.5 Tariff / IEEE 1547 Definition Cross-Reference

IEEE Standard 1547	Tariff
PCC (Point of Common Coupling)	POI (Point of Interconnection)
Point of DR Connection	Not Applicable
EPS (Electric Power System)	Interconnected Transmission Owner Facilities
Area EPS Operator	Interconnected Transmission Owner
Not Applicable	Transmission Provider (PJM)
DG (Distributed Generation)	Interconnected Generation Customer Facilities which are not connected to the Bulk Power Transmission System
DR (Distributed Resources)	Interconnected Generation Facility which is not connected to the Bulk Power Transmission System
Interconnection Equipment	Not Applicable
Interconnection System	Interconnection Facilities
Not Applicable	Interconnection Customer Facilities
Electric Power System, local	Not Applicable
Electric Power System, area	Not Applicable

⁵ In the context used here, transmission systems are systems 69 kV or greater or networked lower voltage systems that are used for backbone energy delivery within smaller geographic areas, much the same as most 69 kV systems.

IEEE Standard 1547	Tariff
Cease to Energize (Cessation of energy outflow capability)	Not Applicable

Note:
The illustration below is for cross-reference of Tariff and IEEE 1547 terms only.



E.6 Applicable Technical Requirements and Standards

IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators of 10 MW and below with the following noted exceptions, additions, and clarifications. IEEE Standard 1547.1 constitutes the requirement for test conformance to IEEE Standard 1547.

IEEE Standard Requirement	Exceptions or Additions
4.1.1 Voltage Regulation	None. See Application Note 1.

IEEE Standard Requirement		Exceptions or Additions
4.1.2	Integration with Area EPS Grounding	None. See Application Note 2.
4.1.3	Synchronization	None. See Application Note 3.
4.1.4.1	Distribution Secondary Grid Networks (under development)	None. See Application Note 4.
4.1.4.2	Distribution Secondary Spot Networks	Exception. ComEd only allows Spot Network interconnections on an exception basis or where state commission regulations specify requirements.
4.1.5	Inadvertent Energization of the Area EPS	None.
4.1.6	Monitoring	None. See Application Note 5.
4.1.7	Isolation Device	None. See Application Note 6.
4.1.8.1	Protection from EMI	None.
4.1.8.2	Surge Withstand Performance	None.
4.1.8.3	Paralleling Device Withstand	None.
4.2.1	Area EPS Faults	PEPCO and PSEG exception for Islanding protection. See Application Notes 7 and 12.
4.2.2	Area EPS Reclosing Coordination	None. See Application Note 13.
4.2.3	Voltage	None. See Application Note 8.
4.2.4	Frequency	None.
4.2.5	Loss of Synchronism	None.
4.2.6	Reconnection to Area EPS: (a) Voltage Requirement (b) Frequency Requirement	None. See Application Note 9. None. See Application Note 9.
4.3.1	Limitation of DC Injection	None.
4.3.2	Limitation of Flicker induced by the DR	None. See Application Note 10.
4.3.4	Harmonics	PPL exception. See Application Note 11.
4.4.1	Unintentional Islanding	PEPCO and PSEG exceptions. See Application Note 12.

IEEE Standard Requirement		Exceptions or Additions
5.1	Design Test	None. See Application Note 14.
5.2	Production Tests	None. See Application Note 14.
5.3	Interconnection Installation Evaluation	None.
5.4	Commissioning Tests	None.
5.5	Periodic Tests	None.

E.6.1 Application Notes

4.1.1 Voltage Regulation. (Application Note 1)

Depending on size of generation (relative to EPS strength) and location of interconnection, the interconnected generation may be required to provide or absorb reactive power and/or follow a voltage schedule to maintain an acceptable voltage profile on the EPS with the addition of the new generating facility.

4.1.2 Integration with Area EPS grounding. (Application Note 2)

Where new transformers are required:

- AP requires a wye-grounded connection on the T.O. side of the DG step up transformer; and
- PEPCO's requirement for an isolation transformer including its configuration at 13.8 kV and above, will be determined on a case by case basis and will depend on the generating facility's location and system configuration.

AP and PEPCO requirements specified above do not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer.

Other Transmission Owners within PJM will accept a delta or wye-ungrounded connection provided that adequate protection is provided by the DG to detect a ground and limit any over-voltage to an acceptable level on the TO's system. Adequate protection includes voltage monitoring on the high side of the DG main transformer using phase to ground connected VTs. Also see Application Note 5 for an additional AEP Application Note for grounding coordination related to operation of isolating devices.

4.1.3 Synchronization. (Application Note 3)

IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.1.4.1 Distribution Secondary Grid Networks. (Application Note 4)

IEEE 1547 presently does not address the requirements for Secondary Grid Networks. These interconnection requests will be evaluated on a case by case basis.

4.1.6 Monitoring. (Application Note 5)

“Each DR unit of 250 kVA or more or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection.” Local monitoring provisions, such as panel meters and indicating lights, may be acceptable to meet these requirements in certain cases.

- An Internet-based SCADA alternative (see Informative Annex #2) was developed as a reliable and economical alternative to direct SCADA communications with the TO. In addition to generally lower installed cost for the “Internet SCADA alternative,” the Internet ongoing communication costs may be more cost effective to other alternatives, especially those that require leased telephone circuits.

Note:

Informative Annex #2 is available on the PJM Web site (<http://www.pjm.com/planning/rtep-development/expansion-plan-process.aspx>) and select from among the 10 specific documents listed under the heading “Information Annex #2 References for Manual 14D, Attachment H.”

- When full-time dedicated SCADA communications are required (see Transmission Owner (“TO”) listing below and refer to the SCADA REQUIREMENTS spreadsheet - Informative Annex #1) the DG Owner, PJM or the TO will provide and/or install a suitable SCADA Remote Terminal Unit in accordance with the specifications provided in Informative Annex #2 or an alternative mutually suitable to the DG Owner, Transmission Owner and PJM.
- The PJM TOs agree to accept the “Internet SCADA alternative” (see Informative Annex #2), in lieu of direct SCADA communications with the TO, except in circumstances where the “Internet SCADA alternative” does not meet certain TO technical requirements specified and justified by the TO.
- If the TO, PJM and DR owner mutually agree, specifications for other suitable interfaces between the DG and TO SCADA can be acceptable. Where applicable, this approach would allow a DR owner to use a SCADA protocol of their choice and provide an interface closer to the Transmission Owner’s SCADA facility. Such an installation must provide adequate communication performance, suitable to PJM and the TO.

Installation of communications facilities (internet service, leased telephone circuits, fiber optics, etc.), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.

Installation of communications facilities (typically leased telephone circuits), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.

PJM requires real-time telemetry data (MW and MVAR) for Capacity Resources, Energy Resources 10MW and above, or Energy Resources able to set LMP. PJM also requires interval revenue metering data (KWH and KVARH data at 5 minute intervals provided hourly).

See the following for specific interconnection requirements based on Transmission Owner Zone:

- Allegheny Power—Requirement for SCADA is determined on a case-by-case basis by Allegheny Power.

- American Electric Power—Real-time telemetry (SCADA) generally required for generation greater than 2.5 MW connected to the distribution system and all connections at transmission voltages.
- Baltimore Gas and Electric—Requires BG&E specified telemetry (periodic, not real time), installed by BG&E, for all generator interconnections.
- Commonwealth Edison Company—Requires real-time telemetry for any interconnection of 10 MW or greater, or for interconnections where transfer trip is required (generally 2.5 MW and above) for the interconnection.
- Dayton Power and Light—Determines real-time telemetry (SCADA) requirements on a case-by-case basis.
- Dominion—Requires a SCADA RTU compatible with Dominion’s SCADA system when the ratio of “Light Local Load” to Maximum Rated Generation Capacity ratio is less than 5.
- Duquesne Light Company—At DLC's discretion the Interconnection Customer can be required to install and maintain a dedicated communications link, compatible with DLC's equipment, to provide telemetry (SCADA) to DLC's Operation Center. The preferred communications protocol for RTU communications is DNP 3.0. The installed SCADA shall comply with the current NERC Cyber Security standards.
- First Energy—FE determines real time telemetry (SCADA) requirements on a case by case basis for interconnection to the radial distribution system. Real time telemetry is required for all interconnections to the Transmission System, generally 23 kV and above.
- Old Dominion Electric Cooperative—ODEC requires real-time SCADA for DG resources in the 2-10 MW range, to include MW and MVAR and status of the interconnecting circuit breaker. This does not necessarily imply a full RTU but could be a data link with the plant / unit control system. DNP 3.0 is the supported protocol.
- Orange and Rockland— All facilities over 1,000 kW connected to the distribution system must have equipment to continuously telemeter the following data to Orange and Rockland's Energy Control Center via a leased telephone line. This data will be provided through the installation of a REMOTE TERMINAL UNIT (RTU) in the Developer's facility. The RTU shall use DNP 3.0 protocol (unless otherwise stated).
- PECO Energy - Requires real-time telemetry for interconnections of 5 MW or greater.
- PHI Companies (Atlantic City Electric Co., Delmarva Power & Light Co. and Potomac Electric Power Co.)—Atlantic City Electric Co. and Delmarva Power & Light Co. require a RTU for all generator interconnections, and real-time MWH and MVH telemetry for all interconnections for which generators participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 3 MW and above.

Note:

The specific location and circumstances of a generator interconnection may make telemetry necessary, even when telemetry would not ordinarily be required.

- PEPCO requires a RTU for all generator interconnections, and real time telemetry for all interconnections that participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 10 MW and above.
- PPL—Requires full-time dedicated SCADA RTU compatible with PPL EU's SCADA system for interconnections 2.5 MW and above or at 69 kV and above.
- PSEG—Real-time telemetry (SCADA) requirement is determined on a case-by-case basis. Smaller MW size generator interconnections usually require a low-cost alternative system.
- UGI—Requires real-time telemetry (SCADA) compatible with the UGI SCADA system for all interconnections 1MW or greater and for all 66 kV and above interconnections.

4.1.7 Isolation Device Requirement. (Application Note 6)

When the Area EPS operating practices require an isolation device, that device must be readily accessible to the Area EPS operator, lockable in the open position, and must provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator, and the Area EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate its generator to maintain electric supply to all or a portion of its load on the Local EPS during an outage of the Area EPS.

A draw-out breaker may be used to meet the Isolation Device requirement if it is lockable in the withdrawn position and has a visible position indicator.

For facilities interconnecting at voltages exceeding 600 volts, when required by the EDC, the Isolating Device required to allow EDC personnel to safely isolate the generator must have a ground grid designed and installed in accordance with IEEE 80 and to specifications to be provided by the EDC. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to EDC personnel and properly trained operators designated by the Customer. Designated Customer personnel may be required to learn and adhere to the EDC's "Switching and Tagging" procedures.

4.2.1 Area EPS Faults

Area EPS Fault Protection requirement for typical interconnection: (Figures 7A, 7B and 7C on the following pages are intended to be representative of typical connections to radial and networked lines, specific requirements will be determined by PJM and the T.O during PJM Feasibility and Impact Studies on a case-by-case basis.)

Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

Typical Protective Relaying Functional Requirements	
27	Under-voltage (3 phases, 1 phase if 50/51G can be applied)
59	Over-voltage (3 phases, 1 phase if 50/51G can be applied)

Typical Protective Relaying Functional Requirements	
81O	Over-frequency (1 phase required)
81U	Under-frequency (1 phase required)
25	Synchronizing check (1 phase required)
32*	Power* (If required, 1 or 3 phase depending on type)
50/51**	Phase instantaneous and time overcurrent (3 phases if required), or
21**	Phase distance relay (3 phases if required)
50/51G***	Ground instantaneous and time overcurrent (1 if applicable)
<p>* If required due to reverse power limitations.</p> <p>** 50/51 or 21 but not both required.</p> <p>*** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault</p>	

Additional Protective Relaying Functional Requirements (as Required)

- Dead line closing control (27 and/or 25 function) at EPS source breaker(s), line recloser(s), etc.
- Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.
- Also see Application Notes 7 and 10 for transfer trip and unbalance functional requirements.
- Voltage Unbalance Protection—In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

Note:

The present version of IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (Section 1.3 Limitations - “Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,...”). From a practical standpoint, this represents an upper limit of 2.5 to 5 MW on typical 13 kV EDC distribution circuits, unless it is a dedicated circuit constructed for the sole purpose of interconnecting the DR. Larger facilities will generally require interconnection to the EDC’s sub-transmission or transmission system. These larger facilities may require additional or specific protection equipment necessary to coordinate with the EDC’s protection practices. Additional AEP Application.

In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to voltage unbalance already present from **existing** customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.

**Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System
 Typical and Additional Protective Relaying Functional Requirements**

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.
- In general, requirements developed to connect 10 MVA and smaller generation to looped networked sub-transmission systems will be more involved and diverse than those needed for radial distribution systems. Additional considerations may be required.

**Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System
 Typical and Additional Protective Relaying Functional Requirements**

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.

Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

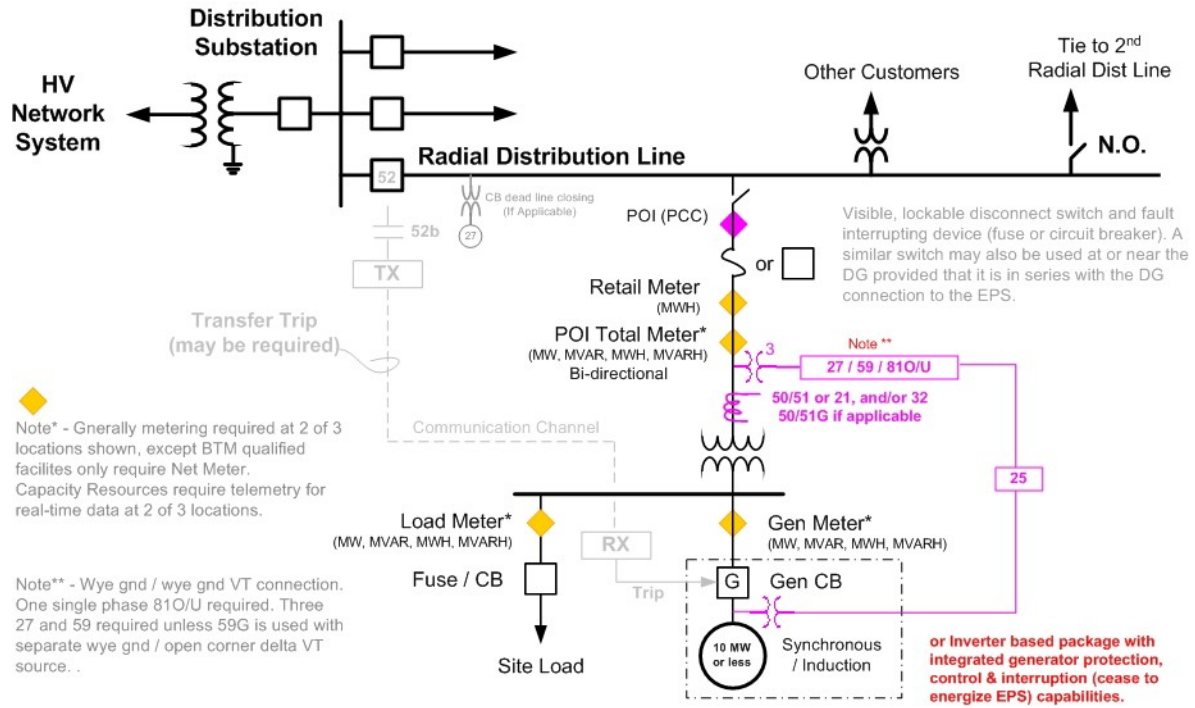


Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

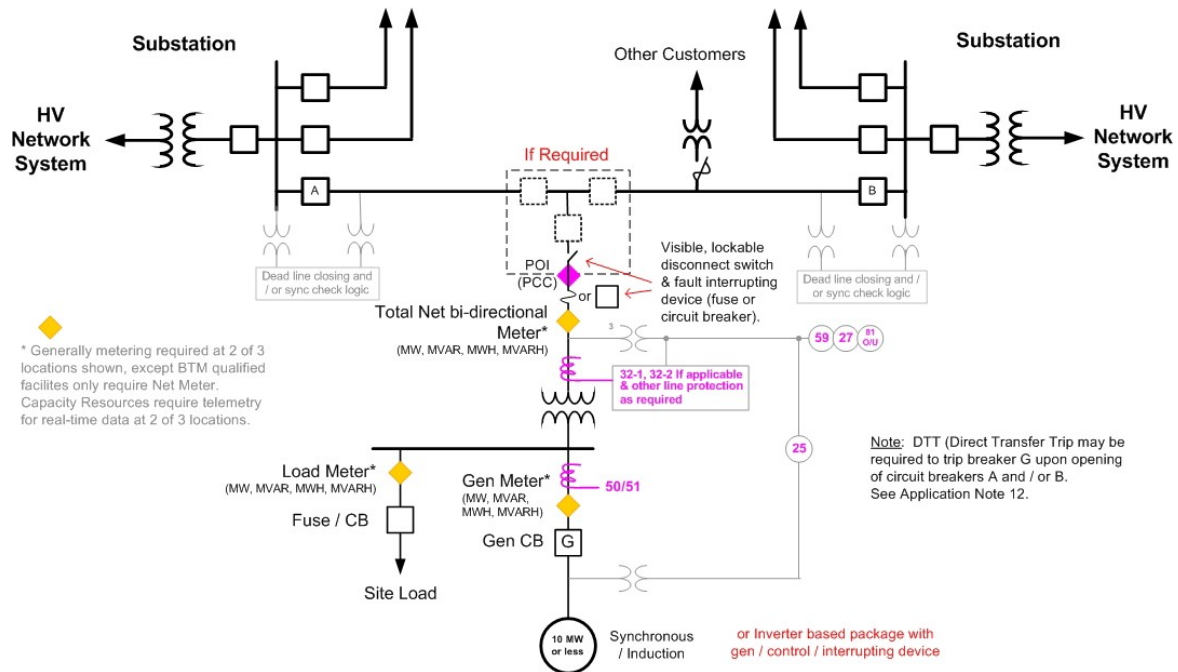
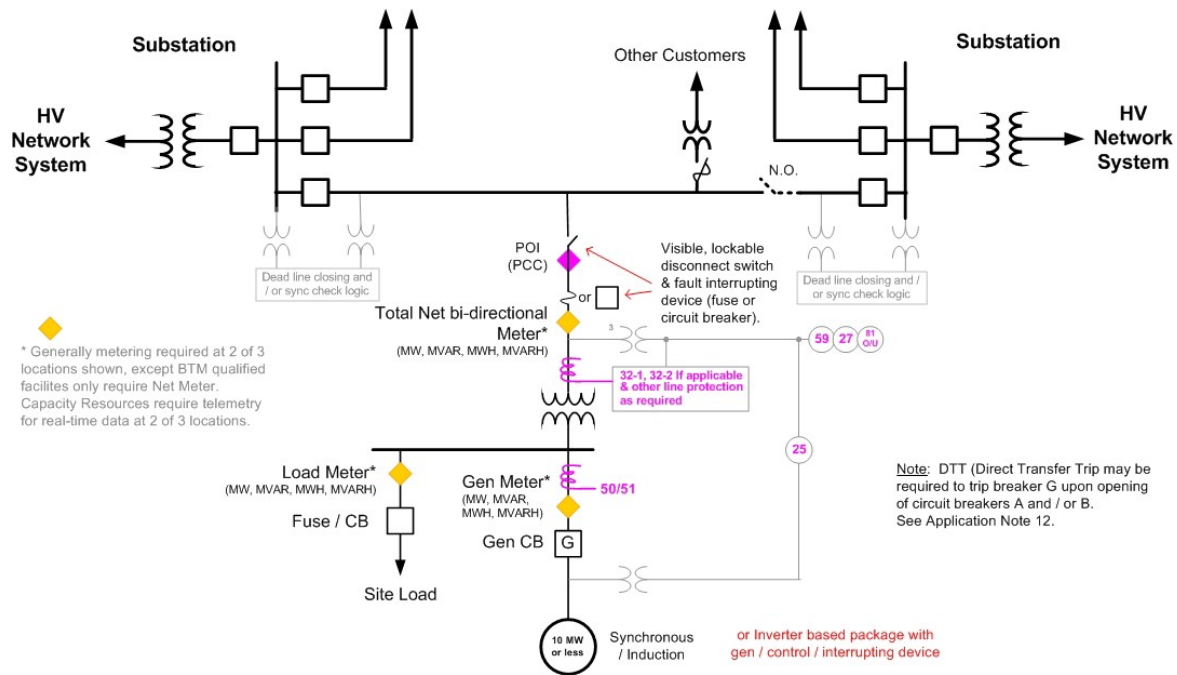


Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System



4.2.3 Voltage. (Application Note 8)

In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be Phase - Ground connected for all three phases.

Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

4.2.6 Reconnection to Area EPS. (Application Note 9)

For larger generating units, an Area EPS may require verbal communication with the System Operator before returning generation to the system.

4.3.2 Limitation of Flicker induced by DR. (Application Note 10)

Requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.3.3 Harmonics. (Application Note 11)

In addition to the IEEE 1547 Harmonics requirement [i.e., each DG installation must, at its PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 (excerpt IEEE 519 Table 10.3)] when multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit. However, the aggregate impact of all the DG units

could still cause voltage distortion, which would impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519, Table 11.1. If the limits described in IEEE 519, Table 11.1 are exceeded, the offending DG is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.

Note:

Additional PPL Application Note: PPL has a requirement for any one Customer (load, generation, etc.) to limit the voltage THD (Total Harmonic Distortion) to 2.5% or less for distribution voltages and 1.5% at 69 kV. PPL allows a smaller fixed limit for each customer thereby sharing allowable harmonic contribution rather than applying a first-come first-served principle to successive interconnection requests.

4.4.1 Unintentional Islanding. (Application Note 12)

The Unintentional Islanding requirement can be met by the following:

- Transfer trip.
- Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically the islanded load must be greater than two to three times the maximum net islanded DR output.*
- DR certified to pass an anti-islanding test.
- Reverse or minimum power flow Relay limited.
- Other anti-islanding means such as forced frequency or voltage shifting.

* Exceptions to B above:

- PSEG—Option B only applicable to aggregate DR interconnections of 1MW and below.
- PEPCO—Option B generally not applicable for DR interconnections which export energy to the PEPCO system regardless of generation and load mismatch.

In accordance with Section 4.2.2 Area EPS reclosing coordination, a 2-second response time may not be adequate to coordinate with the Area EPS reclosing practices. This may result in damage to the generator upon reclosing of the EPS source. In some instances, on a case-by-case basis, the EPS operator may allow the reclosing time to be increased or add synchronism check supervision to provide coordination. Increasing the reclosing time in some cases will have an unreasonable impact on other customers. Other means, such as transfer trip, must then be used to insure isolation of the generator before automatic circuit reclose.

Options for Satisfying 5.1 Design and 5.2 Production Test Requirements.

- Design and Production tests requirements may be satisfied with certified equipment, although certified equipment is not required, consistent with the following criteria:

- The small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with IEEE 1547.1 and the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed below, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its Web site and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.
- The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
- Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL or periodic tests per IEEE 1547 Section 5.5.
- If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an interconnection customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.
- Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.
- An equipment package does not include equipment provided by the utility.
- Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection technical requirements shall be considered certified under these procedures for use in that state.

E.7 Relevant Codes and Standards

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- NFPA 70 National Electrical Code

- IEEE Std C37.90.1-1989 (R1944) IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995) IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002) IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002) IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V) and Less) Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment -Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment E-1: Small Generator (greater than 10 MW up to 20 MW) Technical Requirements and Standards

Scope

The PJM Small Generator Interconnection Applicable Technical Requirements and Standards (“Small Generator Standards – Attachment E-1”) shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of greater than 10 MW up to 20 MW at the point of interconnection.

Attachment E-1 shall be read and construed as to be consistent with the PJM Tariff (“Tariff”). In the event of any inconsistency between the terms and conditions of Attachment E-1 and the terms and conditions of the Tariff, the terms of the Tariff shall control. All terms contained in Attachment E-1 shall be defined as defined by the Tariff. While PJM strives to ensure that the information reflected herein is complete, accurate and reliable, it expressly disclaims any warranty, whether express or implied, as to information contained. Entities relying on the information contained herein do so at their own risk.

Purpose

To align the applicable technical requirements for Small Generator Interconnections (Small Generators are 20 MW and less per PJM’s FERC-approved Tariff) used within PJM with the IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems to facilitate transparency for perspective Generator Interconnection Customers, pre-certification entities (see 5.1 and 5.2) and equipment manufacturers doing business within the PJM footprint.

Because IEEE Standard 1547 and PJM’s Applicable Standard “Attachment H” to PJM Manual 14B are limited to a maximum of 10 MW and primarily intended for generator interconnections to radial distribution systems, PJM stakeholders, through the Small Generator Interconnection Working Group, recognized a need to fill the gap between 10 MW and 20 MW by developing a companion Applicable Standard based on the core IEEE 1547 requirements with changes and additions as required to address the larger MW size and greater diversity of Electric Power System configurations to be included.

Background and Discussion

Attachment E-1 was developed by the PJM Small Generator Interconnection Working Group (“SGIWG”). The Small Generation Standards define the uniform technical requirements that each Interconnected Transmission Owner (“ITO”) and Electric Distribution Company (“EDC”) require for interconnecting to their facilities. The requirements as defined herein will govern for the interconnection of distributed generation greater than 10 MW up to 20 MW. Attachment E-1 is a companion document to Attachment E: Small Generator (10 MW or Less) Technical Requirements and Standards.

ITOs and EDCs may, by mutual agreement, elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein, but may not add requirements to IEEE 1547 other than the exceptions and conditions contained herein. For Small Generators qualifying for interconnection under state rules, the state-approved technical requirements and procedures shall govern. In the event that a Small Generator has interconnected under

state rules and thereafter elects to participate in any PJM market, such Small Generator must comply with the terms of PJM's Small Resource Interconnection Procedure Manual and these Small Generation Standards. The Small Generator must submit a completed Feasibility Study Request (Attachment "N" of the Tariff), and will be responsible for any subsequent study costs. Additionally, the Small Generator will be required to execute PJM's three-party Interconnection Service Agreement with PJM and the local Transmission Owner, and to the extent applicable, an Electric Distribution Company as the case may be.

General Application Note for Transmission System Interconnections

In its present form IEEE Standard 1547 is primarily intended to address generator interconnections of 10 MVA or less to radial distribution systems. In order to extend the use of IEEE Standard 1547 beyond this scope to include connection to transmission facilities, it is necessary to clarify the meaning of Section 4.2.1 to assure that system protection requirements are compatible with the established reliability criteria used for those systems.

IEEE Standard 1547 Section 4.2.1 (Area EPS Faults) requires that “the DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.” For Transmission Interconnections this implies that the protection scheme(s) be compatible and coordinate with the Area EPS protection scheme(s) used for the line or substation to which it is interconnected or compatible and coordinates with new protection equipment installed due to the connection of the generation to this facility.

Generator installations greater than 10 MW are not typically interconnected to radial distribution circuits of nominal 13 kV or less. 10 MW to 20 MW generator interconnections will generally be to system voltages of 26 kV and higher which may be operated radially with normally open ties to other lines or networked and operated more similar to higher voltage transmission systems.

Tariff / IEEE 1547 Definition Cross-Reference

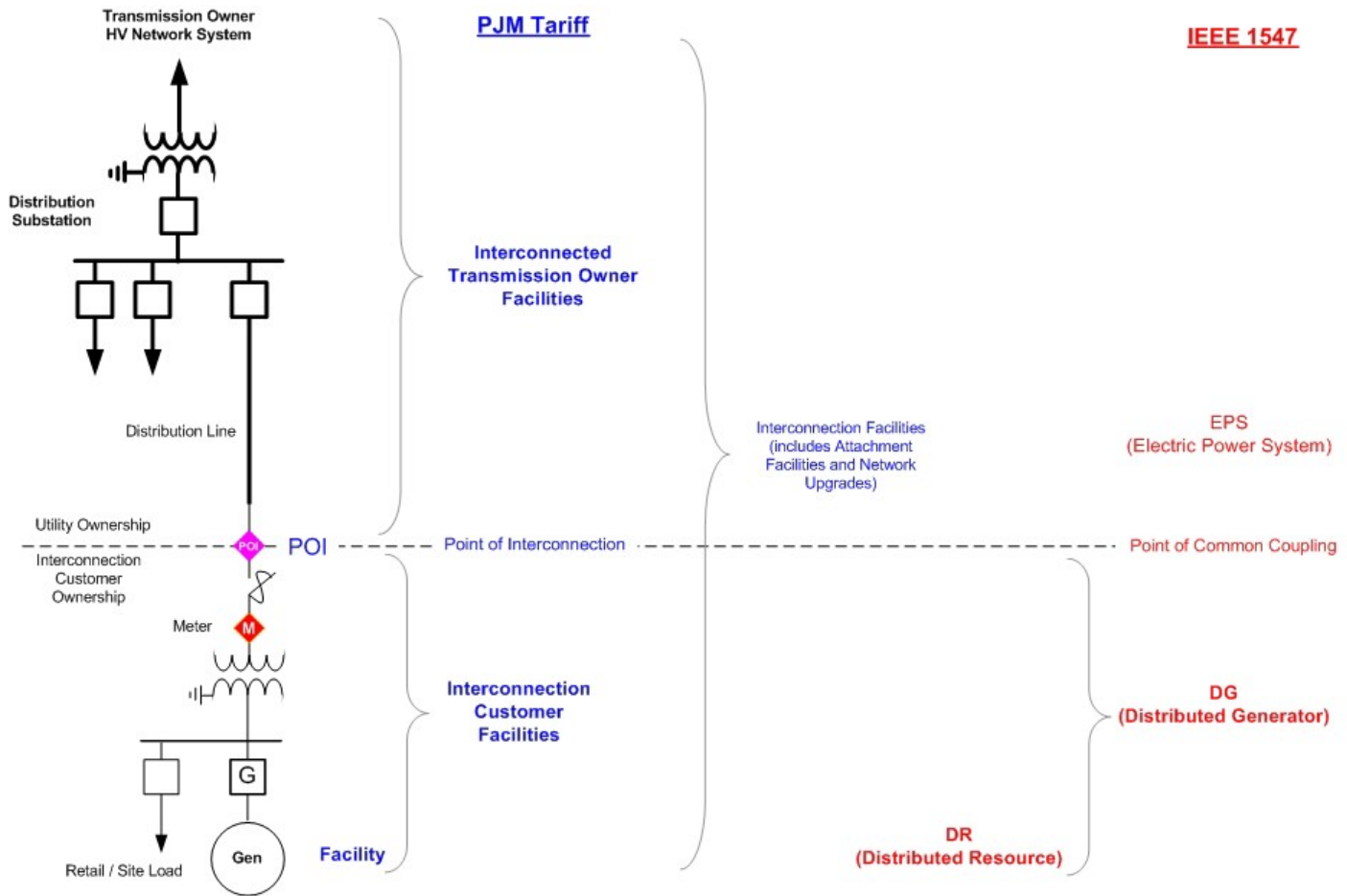
<u>IEEE Standard 1547</u>	<u>Tariff</u>
PCC (Point of Common Coupling)	POI (Point of Interconnection)
Point of DR Connection	Not Applicable
EPS (Electric Power System)	Interconnected Transmission Owner Facilities
Area EPS Operator	Interconnected Transmission Owner
Not Applicable	Transmission Provider (PJM)
DG (Distributed Generation)	Interconnected Generation Customer Facilities which are not connected to the Bulk Power Transmission System

⁶ In the context used here, transmission systems are systems 69 kV or greater, or networked lower voltage systems which are used for backbone energy delivery within smaller geographic areas much the same as most 69 kV systems.

<u>IEEE Standard 1547</u>	<u>Tariff</u>
DR (Distributed Resources)	Interconnected Generation Facility which is not connected to the Bulk Power Transmission System
Interconnection Equipment	Not Applicable
Interconnection System	Interconnection Facilities
Not Applicable	Interconnection Customer Facilities
Electric Power System, local	Not Applicable
Electric Power System, area	Not Applicable
Cease to Energize (Cessation of energy outflow capability)	Not Applicable

Note:

Illustration below is for cross-reference of Tariff and IEEE 1547 terms only.



Applicable Technical Requirements and Standards

IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators greater than 10 MW up to 20 MW with the following noted exceptions, additions, and clarifications. IEEE Standard 1547.1 constitutes the requirement for test conformance to IEEE Standard 1547.

IEEE Standard Requirement		Exceptions or Additions
4.1.1	Voltage Regulation	None. See Application Note 1.
4.1.2	Integration with Area EPS Grounding	None. See Application Note 2.
4.1.3	Synchronization	None. See Application Note 3.
4.1.4.1	Distribution Secondary Grid Networks (under development)	Not applicable for generator interconnections 10 MW and above.
4.1.4.2	Distribution Secondary Spot Networks	Generally not applicable for generator interconnections of 10 MW and greater. Rare

IEEE Standard Requirement		Exceptions or Additions
		exceptions to be handled on a case-by-case basis.
4.1.5	Inadvertent Energization of the Area EPS	None.
4.1.6	Monitoring	None. See Application Note 4.
4.1.7	Isolation Device	None. See Application Note 5.
4.1.8.1	Protection from EMI	None.
4.1.8.2	Surge Withstand Performance	None.
4.1.8.3	Paralleling Device Withstand	None.
4.2.1	Area EPS Faults	PEPCO and PSEG exception for Islanding protection. See Application Notes 6, 7 & 11.
4.2.2	Area EPS Reclosing Coordination	None. See Application Note 12.
4.2.3	Voltage	None. See Application Note 7.
4.2.4	Frequency	None.
4.2.5	Loss of Synchronism	None.
4.2.6	Reconnection to Area EPS Voltage Requirement Frequency Requirement	None. See Application Note 8. None. See Application Note 8.
4.3.1	Limitation of DC Injection	None.
4.3.2	Limitation of Flicker induced by the DR	None. See Application Note 9.
4.3.4	Harmonics	PPL exception. See Application Note 10.
4.4.1	Unintentional Islanding	PEPCO and PSEG exceptions. See Application Note 11.
5.1	Design Test	None. See Application Note 13.
5.2	Production Tests	None. See Application Note 13.
5.3	Interconnection Installation Evaluation	None.
5.4	Commissioning Tests	None.
5.5	Periodic Tests	None.

Application Notes

4.1.1 Voltage Regulation. (Application Note 1)

Depending on size of generation (relative to EPS strength) and location of interconnection, the interconnected generation may be required to provide or absorb reactive power and/or follow a voltage schedule to maintain an acceptable voltage profile on the EPS with the addition of the new generating facility.

4.1.2 Integration with Area EPS grounding. (Application Note 2)

Where new transformers are required:

- AP requires a wye-grounded connection on the T.O. side of the DG step up transformer; and
- PEPCO's requirement for an isolation transformer including its configuration at 13.8 kV and above, will be determined on a case-by-case basis and will depend on the generating facility's location and system configuration.

AP and PEPCO requirements specified above do not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer.

Other Transmission Owners within PJM will accept a delta or wye-ungrounded connection provided that adequate protection is provided by the DG to detect a ground and limit any over-voltage to an acceptable level on the TO's system. Adequate protection includes voltage monitoring on the high side of the DG main transformer using phase to ground connected VTs. Also see Application Note 5 for an additional AEP Application Note for grounding coordination related to operation of isolating devices.

4.1.3 Synchronization. (Application Note 3)

IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.1.6 Monitoring. (Application Note 4)

Aggregate DR interconnection greater than 10 MW at a single PCC shall have SCADA provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection. (See Informative Annex #1 for specific monitored quantities required by each Area EPS Operator.)

- An Internet-based SCADA alternative (see Informative Annex #2), was developed as a reliable and economical alternative to direct SCADA communications with the Area EPS Operator. In addition to generally lower installed cost for the "Internet SCADA alternative," the Internet ongoing communication costs may be more cost effective to other alternatives, especially those that require leased telephone circuits.
- When full-time dedicated SCADA communications are required (see Informative Annex #1) the DG Owner, PJM or the Area EPS Operator will provide and/or install a suitable SCADA Remote Terminal Unit in accordance with the specifications provided

in Informative Annex #2 or an alternative mutually suitable to the DG Owner, Area EPS Operator and PJM.

- The PJM Transmission Owners (TOs) agree to accept the “Internet SCADA alternative” (see Informative Annex #2) in lieu of direct SCADA communications with the TO, except in circumstances where the “Internet SCADA alternative” does not meet certain TO technical requirements specified and justified by the TO.
- If the TO, PJM and DR owner mutually agree, specifications for other suitable interfaces between the DG and TO SCADA can be acceptable. Where applicable, this approach would allow a DR owner to use a SCADA protocol of their choice and provide an interface closer to the TO’s SCADA facility. Such an installation must provide adequate communication performance, suitable to PJM and the TO.
- The Interconnection Customer is responsible for the protection of the communications circuit in accordance with IEEE 487-2000, or later revisions, and any additional requirements of the communications circuit provider.
- Area EPS Operators will typically require SCADA monitoring at the Point of Interconnection as well as at the generating units.

4.1.7 Isolation Device Requirement. (Application Note 5)

When the Area EPS operating practices require an isolation device, that device must be readily accessible to the Area EPS operator, lockable in the open position, and must provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator, and the Area EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate their generator to maintain electric supply to all or a portion of their load on the Local EPS during an outage of the Area EPS.

A drawout breaker may be used to meet the Isolation Device requirement if it is lockable in the withdrawn position and has a visible position indicator.

The Isolating Device required to allow Area EPS Operator personnel to safely isolate the generator must have a ground grid designed and installed in accordance with IEEE 80 and to specifications to be provided by the EDC. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to the Area EPS Operator’s personnel and properly trained operators designated by the Customer. Designated Customer personnel may be required to learn and adhere to the Area EPS Operator’s “Switching and Tagging” procedures.

4.2.1 Area EPS Faults. (Application Note 6, 7, & 11)

Area EPS Fault Protection requirement for typical interconnection: (Figures 6A, 6B and 6C on the following pages are intended to be representative of typical connections to radial and networked lines. Specific requirements will be determined by PJM and the Area EPS Operator during PJM Feasibility and Impact Studies on a case-by-case basis.)

Figure 6A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

Typical Protective Relaying Functional Requirements	
27	Under-voltage (3 phases, 1 phase if 50/51G can be applied)
59	Over-voltage (3 phases, 1 phase if 50/51G can be applied)
81O	Over-frequency (1 phase required)
81U	Under-frequency (1 phase required)
25	Synchronizing check (1 phase required)
32*	Power* (If required, 1 or 3 phase depending on type)
50/51**	Phase instantaneous and time overcurrent (3 phases if required), or
21**	Phase distance relay (3 phases if required)
50/51G***	Ground instantaneous and time overcurrent (1 if applicable)
<p>* If required due to reverse power limitations.</p> <p>** 50/51 or 21 but not both required.</p> <p>*** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault.</p>	

Additional Protective Relaying Functional Requirements (as Required)

- Dead line closing control (27 and / or 25 function) at EPS source breaker(s), line recloser(s), etc.
- Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.
- Also see Application Notes 7 and 11 for transfer trip and unbalance functional requirements.
- Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment, under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

Note:

The present version of IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (Section 1.3 Limitations - “Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,...”). From a practical standpoint, this represents an upper limit of 2.5 to 5 MW on typical 13 kV EDC distribution circuits, unless it is a dedicated circuit constructed for the sole purpose of interconnecting the DR. Larger facilities will generally require interconnection to the EDC’s sub-transmission or transmission system. These larger facilities may require additional or specific protection equipment necessary to coordinate with the EDC’s protection practices.

Additional AEP Application Note: In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to voltage unbalance already present from existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.

Figure 6B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

- Typical and Additional Protective Relaying Functional Requirements
- Same as Figure 6A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.
- In general, line protection requirements to connect generation greater than 10MW to looped networked sub-transmission systems will be more involved and diverse than those needed for connection to radial distribution systems. Additional considerations may be required.

Figure 6C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System

- Typical and Additional Protective Relaying Functional Requirements
- Same as Figure 6A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.

Figure 6A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

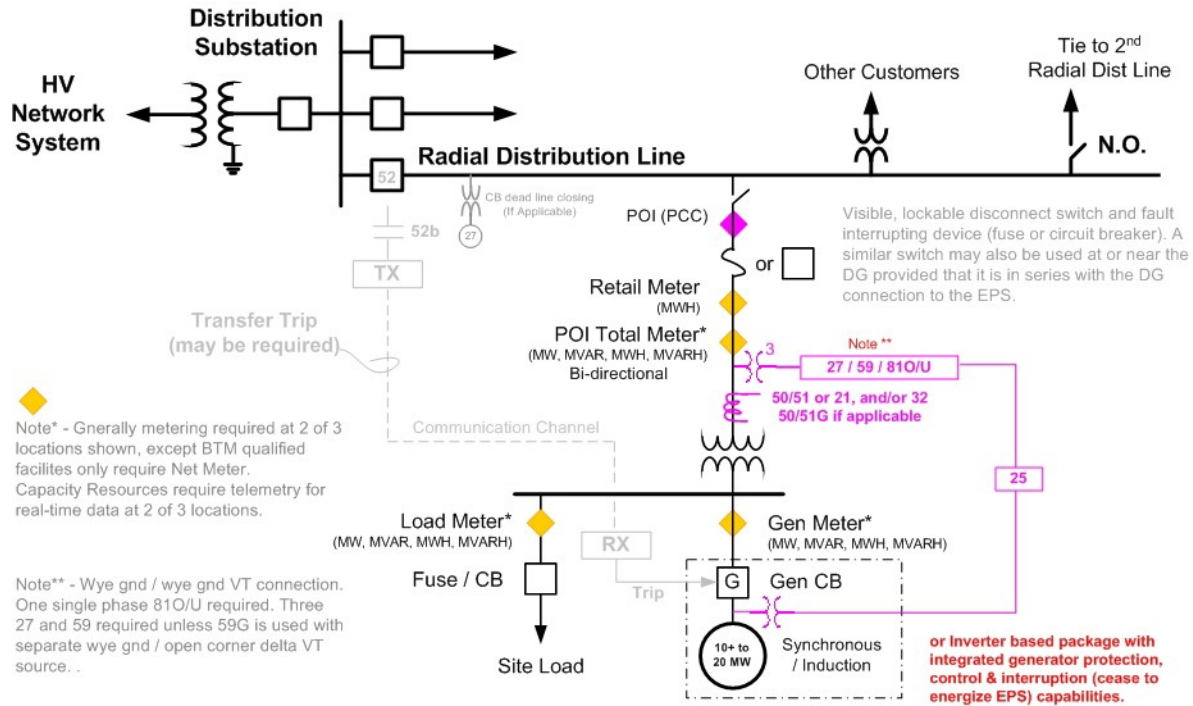


Figure 6B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

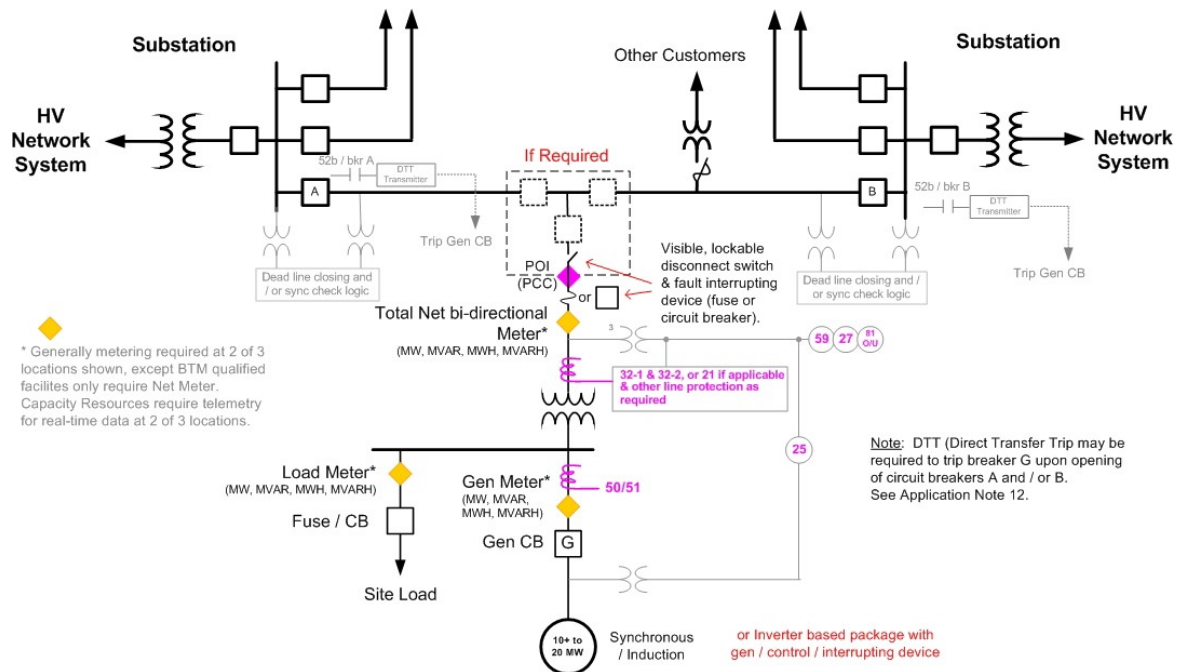
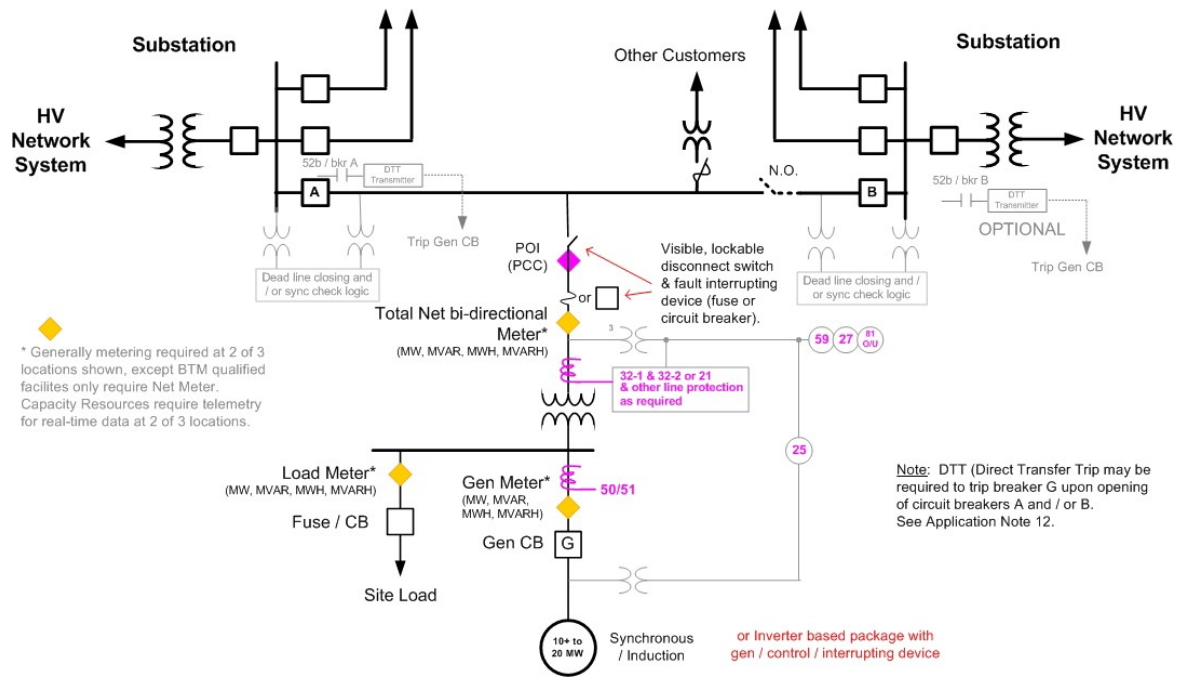


Figure 6C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System



4.2.2 Area EPS Reclosing Coordination. (Application Note 12)

In accordance with Section 4.2.2 Area EPS reclosing coordination, a 2-second response time may not be adequate to coordinate with the Area EPS reclosing practices. This may result in damage to the generator upon reclosing of the EPS source. In some instances, on a case-by-case basis, the EPS operator may allow the reclosing time to be increased or add synchronism check supervision to provide coordination. Increasing the reclosing time in some cases will have an unreasonable impact on other customers. Other means, such as transfer trip, must then be used to insure isolation of the generator before automatic circuit reclose.

Options for Satisfying 5.1 Design and 5.2 Production Test Requirements. (Application Note 13)

Design and Production tests requirements may be satisfied with certified equipment, although certified equipment is not required, consistent with the following criteria:

- The small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with IEEE 1547.1 and the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed below, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification and with consumer approval, the test data itself. The NRTL may make such information available on its Web site and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

- The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
- Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL or periodic tests per IEEE 1547 Section 5.5.
- If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an interconnection customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.
- Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.
- An equipment package does not include equipment provided by the utility.
- Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection technical requirements shall be considered certified under these procedures for use in that state.

4.2.3 Voltage. (Application Note 7)

In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be Phase - Ground connected for all three phases.

Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment, under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

4.2.6 Reconnection to Area EPS. (Application Note 8)

For larger generating units, an Area EPS may require verbal communication with the System Operator before returning generation to the system.

4.3.2 Limitation of Flicker induced by DR. (Application Note 9)

Requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement that must be met for 4.3.2 is to not cause voltage and /or frequency disturbances that are objectionable to other EPS customers during actual operation of DR.

4.3.3 Harmonics. (Application Note 10)

In addition to the IEEE 1547 Harmonics requirement (i.e., each DG installation must, at its PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 [excerpt IEEE 519 Table 10.3]) when multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit; however, the aggregate impact of all the DG units could still cause voltage distortion that would adversely impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519 limits. If the limits described in IEEE 519 are exceeded, the offending DG (in most cases the last to connect) is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.

Note:

Additional PPL Application Note: PPL has a requirement for any one Customer (load, generation, etc.) to limit the voltage THD (Total Harmonic Distortion) to 2.5% or less for distribution voltages and 1.5% at 69 kV. PPL allows a smaller fixed limit for each customer, thereby sharing allowable harmonic contribution rather than applying a first-come first-served principle to successive interconnection requests.

4.4.1 Unintentional Islanding. (Application Note 11)

The Unintentional Islanding requirement can be met by the following:

- Transfer trip.
- Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically, the islanded load must be greater than two to three times the maximum net islanded DR output.*
- DR certified to pass an anti-islanding test.
- Reverse or minimum power flow relay limited.
- Other anti-islanding means such as forced frequency or voltage shifting.

* Exceptions to B above:

- PSEG – Option B only applicable to aggregate DR interconnections of 1MW and below.
- PEPCO – Option B generally not applicable for DR interconnections that export energy to the PEPCO system regardless of generation and load mismatch.

Relevant Codes and Standards

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

- NFPA 70 National Electrical Code
- IEEE Std C37.90.1-1989 (R1944) IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995) IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002) IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002) IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V) and Less) Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment -Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment F: Generation Interconnection Feasibility Study Data

F.1 Scope

This Generation Interconnection Feasibility Study data attachment to Manual 14A is intended to provide a listing of the data which is required so that an Interconnection Customer may complete the data form located on the PJM website (link given below). Completion of the form on the web site, and submission of the additional data as listed at the link provided below, is necessary for an Interconnection Request to be deemed a valid request.

Link location for data submittal: <http://www.pjm.com/planning/rtep-development/expansion-plan-process/form-attachment-n.aspx>

F.2 Data Requirements for PJM RTEPP Feasibility Studies

Feasibility Studies are conducted to identify transmission expansion needed to maintain the system reliability given your generation onto the network. The data submitted is required to perform the power flow, and short circuit analysis which are necessary for the Feasibility Study Phase.

PJM uses the following programs to perform the Feasibility Analysis:

- 1. PSS/E program from PTI, Inc. (power flow)
- 2. Aspen from Advanced Systems for Power Engineering, Inc.(short circuit)

All data must be provided on an individual unit basis.

For example, a combined cycle plant with two identical Combustion Turbines (CTs), and one Steam Turbine (ST), would have 2 submissions of the data request form. One submission for the CTs, and one submission for the ST.

If the final unit specifications are not certain an approximation must be made.

When more information is available, the Interconnection Customer must provide an update to PJM so that the typical model may be replaced with a detailed model based on the actual unit purchased.

The data listed in Attachment F-1 is required for a Generation Interconnection Feasibility Study.

Attachment F-1: Feasibility Study Data Form

Note:

This form is not to be used for submitting a Feasibility Study Form. Data must be submitted through the PJM website: <http://pjm.com/planning/rtep-development/expansion-plan-process.aspx>

* Denotes Required Field

Customer Information

* Name of person completing form:

* Title:

* Email:

* Phone number:

* Agreement date (current date):

* Interconnection Customer name (Company name):

Interconnection customer address

* Address one:

Address two:

* City:

* State:

* Zip / Postal code:

Unit Information

* State where point of interconnection located:

* County:

* Fuel type:

- | | |
|--------------------------------------|--|
| <input type="checkbox"/> Biomass | <input type="checkbox"/> Oil |
| <input type="checkbox"/> Coal | <input type="checkbox"/> Offshore Wind |
| <input type="checkbox"/> Diesel | <input type="checkbox"/> Solar |
| <input type="checkbox"/> Hydro | <input type="checkbox"/> Storage |
| <input type="checkbox"/> Methane | <input type="checkbox"/> Wind |
| <input type="checkbox"/> Natural Gas | <input type="checkbox"/> Wood |
| <input type="checkbox"/> Nuclear | <input type="checkbox"/> Other |

Note:

PJM will accept 10 acres per MW for flat land, 3 acres per MW for placement on a ridge. Ocean-based much have a filed application with the Federal government.

* Location of generating unit site:

* Identification of evidence of ownership interest in, or right to acquire or control, the generating site::

Size in megawatts of generating unit or increase in capacity of existing generating unit

* Maximum facility output (as defined in Part I, Common Service Provisions of the Tariff under OATT Definitions) of the generating unit:

* If interconnection request is for an increase in capacity of existing generating unit, specify size in megawatts of the increase in capacity of existing generating unit:

If yes, explain in detail, how is the additional MW injection being obtained? Make sure to identify the components being subjected to work or improvements.

Illustrative examples include: (below are examples not including all possible responses)
 Generator ID being upgraded by rewinding or additional work such as...
 Auxiliary or station load being reduced by...
 New equipment being added to improve efficiency (e.g. measurement uncertainty recapture)
 Rotor replacement for unit ID resulting in ...
 Demonstrated capability of higher power output. No changes to power plant.

Specify any portion of the facility's capacity that you wish to be a Capacity Resource or Energy Resource

* MW capacity resource:

MW

Note:

Wind will be assigned class average - currently 13% of MFO without evidence. If requesting higher than 13%, evidence should be engineering evaluation showing greater capability due to wind available at location.

Solar project will be assigned class average - currently 38% of MFO without evidence. If requesting higher than 38%, evidence should be engineering evaluation showing greater capability due to tracking or location and include cloud cover for summer period (June 1 - Aug 31 2:00 p.m. - 6:00 p.m.)

* MW energy resource:

MW

* Description of the equipment configuration:

* Planned date the generating unit or increase in capacity will be in service:

* Is the generating unit behind the meter generation?

Yes No

If yes, other information:

General Info

* Connection type. Please select one: Existing substation Line tap/ new substation

If "Existing Substation" is selected specify the following:

* Specify existing substation name:

--

* POI voltage:

KV

--

If "Line tap/new substation" is selected specify line ends:

* Substation A (from):

--

* Substation B (from):

--

* Line voltage:

KV

--

* Total length of line:

Miles

--

Please select one:

Distance from POI to Substation A

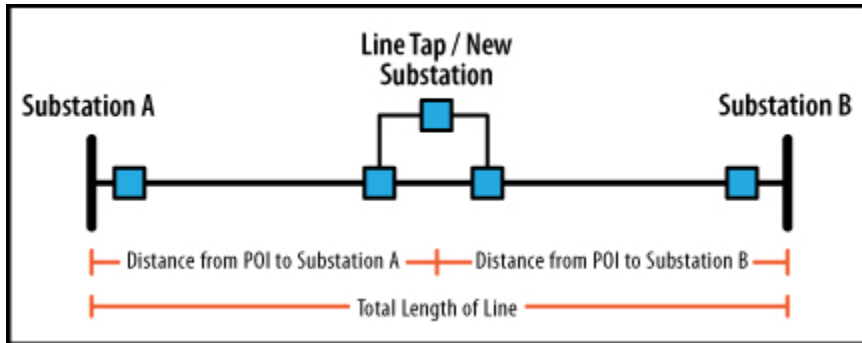
Miles

--

Distance from POI to Substation B

Miles

--



Unit Output

High voltage side of the

Where is the auxiliary load being connected? Please select one:

- Low voltage side of the GSU
 High voltage side of the GSU

Station service load:

MW

MVAR

Maximum Net MW Output:

MW

Maximum Gross MW Output:

MW

Expected Summer Energy Output:

MW

GSU

Main Transformer Form

* Number of machines per transformer:

* MVA base:

MVA

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:

MVA

* Rating 2:

MVA

* Rating 3:

MVA

* Select transformer windings. Please select...

- Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

		R	jX	X/R
* (a) High-side to low-side:	PU			
* (b) High-side to tertiary:	PU			
* (c) Low-side to tertiary:	PU			

Winding Voltages

* High-side:	KV	
* Low-side:	KV	
* Tertiary:	KV	

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	
* Low-side:	
* Tertiary:	
* Tap position:	
Off-nominal Turns Ratio:	
Number of taps:	
Step size:	

* GSU shared with other units? Yes No

Synchronous Generator

The next section below pertains to synchronous generator data (e.g. Biomass, Coal, Diesel, Hydro, Methane, Natural Gas, Nuclear, Oil, etc). If you are not providing data for a synchronous generator, please proceed to Page 99.

Unit generator dynamic data

All reactances and resistance values in PU on Machine MVA Base

* Machine ID (e.g. ST, CT, CT1, CT2, ST2, etc.):

Note: List all the machine IDs that these data corresponds (e.g. CT1, CT2)

* MVA base:

MVA

* Terminal voltage:

KV

* Nominal power factor:

Combined turbine-generator-exciter inertia, H:
 $1 < H < 10$

kWs/kVA

Speed damping coefficient, D:
 $0 \leq D < 3$

P.U.

Generator Saturation

Generator saturation at 1.0 p.u. voltage, S (1.0):
 $0 < S1.0$

PU

Generator saturation at 1.2 p.u. voltage, S (1.2):
 $S1.0 < S1.2$

PU

Unsaturated Reactances

Direct axis synchronous reactance, Xd(i):
 $x_d < 2.5$

PU

Direct axis transient reactance, X'd(i):
 $x'd < 0.5 \times x_d$

PU

Direct axis sub-transient reactance, X''d(i):
 $x''d < x'd$

PU

Quadrature axis synchronous reactance, Xq(i):
 $x_q < x_d$

PU

Quadrature axis transient reactance, X'q(i):
 $x'q < x_q$

PU



Stator leakage reactance, X_l :

PU

Negative sequence reactance, $X_{2(i)}$:

PU

Zero sequence reactance, $X_{0(i)}$:

PU

Saturated Reactances

* Saturated sub-transient reactance, $X''_d(v)$:
 $x'_d < 2.5$

PU

Synchronous reactance, $X_d(v)$:
 $x'_d < 0.5 \times x_d$

PU

Transient reactance, $X'_d(v)$:
 $X''_d(v) < X'_d(i)$

PU

Negative sequence reactance, $X_{2(v)}$:

PU

Zero sequence reactance, $X_{0(v)}$:

PU

Resistances

DC armature resistance, R_a :

Ohms

Positive sequence resistance, R_1 :

PU

Negative sequence resistance, R_2 :

PU

Zero sequence resistance, R_0 :

PU

Time Constants

Direct axis transient open circuit, T'_{do} :
 $1. < T'_{do} < 10.$

sec

Direct axis sub-transient open circuit, T''_{do} :
 $0.01667 < T''_{do} < 0.2$

sec

Quadrature axis transient open circuit, T'_{qo} :
 $0.2 \leq T'_{qo} \leq 1.5$

sec

Quadrature axis sub-transient open circuit, T''_{qo} :
 $0.01667 \leq T''_{qo} \leq 0.2$

sec

Armature three-phase short circuit, T_{a3} :
 $0.025 \leq T_a \leq 0.1$

sec

Wind Farm

The next section below pertains to wind generator data (e.g. offshore wind and wind). If you are not providing data for a wind generator, please proceed to Page 101.

PJM has on file the manufacturer data sheets for the following Wind Turbines:

Acciona AW 1530 1.5 MW, 3.0 MW; Clipper C93 2.5 MW; Gamesa G8x/G90 2 MW; GE 1.5 MW, 1.6 MW, 2.5 MW, 2.75 MW, 4.0 MW; Generic Wind Model (WT3 and WT4) Mitsubishi MWT92/95 2.3 MW, Nordex N90 2.5 MW, N100 2.5 MW, N117 2.4 MW; Repower MM82 2.05 MW; Siemens 2.3 MW, 3.0 MW, 3.6 MW, 4.0 MW, 6.0 MW; Suzlon S88 2.1MW, S97 2.1 MW; Vestas V82 1.8 MW, V90 1.8 MW, 3.0 MW, V100 1.8 MW, V112 3.075 MW.

If the Interconnection Customer intends to install any of the turbines listed above, then that Interconnection Customer must only supply the information listed below which is applicable to a wind plant data request and which is accompanied by an asterisk. If an Interconnection Customer intends to install a turbine other than one (or more) of the models listed above, then all data which follows as being required by a wind plant will be required.

Wind Farm Parameters

* Specify manufacturer:

* Specify model:

* MW Value per turbine (nominal rating):

* Number of wind turbines generators of the selected type:

* MVA base:

MVA

* Terminal voltage:

KV

* Nominal power factor:

PU on MVA base

* Stator resistance, R1:

Ohms

* Saturated sub-transient reactance, X"d(v):

PU on MVA base

Please select a Control Mode:

- Power Factor
- Voltage Control
- Other

Voltage relays?

Yes No

If yes, provide voltage relay settings:

Frequency relays?

Yes No

If yes, provide frequency relay settings:

Additional wind farm compensation?

Yes No

If yes, provide type of reactive compensation (e.g. fixed shunts, switchable shunt bank, dynamic):

Inverter Based Generator

The next section below pertains to inverter based generator data (e.g. solar and storage). If you are not providing data for an inverter based generator, please proceed to Page 103.

Unit generator dynamic data

All reactances and resistance values in PU on Machine MVA Base

* Machine ID (e.g. ST, CT, CT1, CT2, ST2, etc.):

Note: List all the machine IDs that these data corresponds (e.g. CT1, CT2)

* MVA base:

MVA

* Terminal voltage:

KV

* Nominal power factor:

Combined turbine-generator-exciter inertia, H:
 $1 < H < 10$

kWs/kVA

Speed damping coefficient, D:
 $0 \leq D < 3$

P.U.

Generator Saturation

Generator saturation at 1.0 p.u. voltage, S (1.0):
 $0 < S1.0$

PU

Generator saturation at 1.2 p.u. voltage, S (1.2):
 $S1.0 < S1.2$

PU

Unsaturated Reactances

Direct axis synchronous reactance, Xd(i):
 $x_d < 2.5$

PU

Direct axis transient reactance, X'd(i):
 $x'd < 0.5 \times x_d$

PU

Direct axis sub-transient reactance, X''d(i):
 $x''d < x'd$

PU

Quadrature axis synchronous reactance, Xq(i):
 $x_q < x_d$

PU

Quadrature axis transient reactance, X'q(i):
 $x'q < x_q$

PU

Stator leakage reactance, Xl:

PU

Negative sequence reactance, $X2(i)$:

PU

Zero sequence reactance, $X0(i)$:

PU

Saturated Reactances

Saturated sub-transient reactance, $X''d(v)$:
 $x_d < 2.5$

PU

Synchronous reactance, $X_d(v)$:
 $x'_d < 0.5 \times x_d$

PU

Transient reactance, $X'd(v)$:
 $X''d(v) < X''d(i)$

PU

* Negative sequence reactance, $X2(v)$:

PU

* Zero sequence reactance, $X0(v)$:

PU

Resistances

DC armature resistance, R_a :

Ohms

Positive sequence resistance, $R1$:

PU

Negative sequence resistance, $R2$:

PU

Zero sequence resistance, $R0$:

PU

Time Constants

Direct axis transient open circuit, $T'do$:
 $1. < T'do < 10.$

sec

Direct axis sub-transient open circuit, $T''do$:
 $0.01667 < T''do < 0.2$

sec

Quadrature axis transient open circuit, $T'qo$:
 $0.2 \leq T'qo \leq 1.5$

sec

Quadrature axis sub-transient open circuit, $T''qo$:
 $0.01667 \leq T''qo \leq 0.2$

sec

Armature three-phase short circuit, $Ta3$:
 $0.025 \leq Ta \leq 0.1$

sec

Generator Step-up Transformer (GSU)

The next section below pertains to wind or inverter based generator data. If you are not providing data for a wind or inverter based generator data, please proceed to Page 104.

* MVA base:	MVA	<input type="text"/>
-------------	-----	----------------------

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select...

Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

	R	jX	X/R
* (a) High-side to low-side:	PU	<input type="text"/>	<input type="text"/>
* (b) High-side to tertiary:	PU	<input type="text"/>	<input type="text"/>
* (c) Low-side to tertiary:	PU	<input type="text"/>	<input type="text"/>

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>
Step size:	<input type="text"/>

Attachment Line Data

Please complete all required information below.





Voltage level (kV):

KV

--

MVA Base:

MVA

--

Line length:

Miles

--

Conductor type (e.g. ACSR, AAC, AAAC, ACAR, etc.):

--

Total branch positive sequence impedance:

PU

R

jX

--	--

Total branch zero sequence impedance:

PU

--	--

Total branch charging susceptance:

PU

--

Any additional comments on the line?
(e.g two identical parallel lines)

--

Attachment G: System Impact Study Data

G.1 Scope

This System Impact Study data attachment to Manual 14A is intended to provide a listing of the data which is required so that an Interconnection Customer may complete the data form located on the PJM website (link given below). Completion of the form on the web site, and submission of the additional data as listed at the link provided below, is necessary for an Interconnection Request to be deemed a valid request.

Link location for data submittal: <http://pjm.com/planning/rtep-developme/expansion-plan-process.aspx>

Data Requirements for PJM RTEPP System Impact Studies

The data listed in Attachment G-2 must be submitted to ensure proper modeling of Interconnection Requests in the System Impact Study phase. System Impact Studies are conducted to identify transmission expansion needed to maintain the system reliability given the addition of your generation on to the network. The data that is submitted is required to perform the power flow, short circuit and dynamic simulation analyses which are necessary for the Impact Study phase.

PJM uses the following programs to perform the System Impact Study Analysis:

1. PSS/E from PTI, Inc. (power flow and dynamic simulation)
2. Aspen from Advanced Systems for Power Engineering, Inc. (short circuit)

Minimum requirement fields are indicated by *

All data must be provided on an individual unit basis.

For example, a combined cycle plant with two identical Combustion Turbines (CT), and one Steam Turbine (ST), would have 1 submission of the data request form with data for 2 turbines since the two identical CTs can be entered as one turbine.

For a combined cycle plant with two identical Combustion Turbines (CTs) and one Steam Turbine (ST), the two distinct sets of turbine data; one for the two CTs and one for the ST, can be submitted together using the data request form.

If the final unit specifications are not certain an approximation must be made. When more information is available, the Interconnection Customer must provide an update to PJM so that the typical model may be replaced with a detailed model based on the actual unit purchased.

Attachment G-1: Dynamic Model Study Request Form

RECITALS

1. This Agreement, dated as of _____, _____, is entered into by and between _____ ("Customer") and PJM Interconnection, L.L.C. ("Transmission Provider"). Capitalized terms used in this agreement, unless otherwise indicated, shall have the meanings ascribed to them in the PJM Tariff ("Tariff").
2. The Customer has notified the Transmission Provider that it plans to provide a new dynamic model or new version of an existing model for study of a Generation Interconnection Request(s).
3. The Customer shall provide sufficient information regarding the model and any facility information to enable Transmission Provider to evaluate the model for use in future System Impact Study.

PURPOSE OF THE STUDIES UNDER THIS AGREEMENT

4. Transmission Provider shall conduct studies to determine whether the model and information provided will be acceptable for the study of a Generation Interconnection Request. Upon completion of the studies, Transmission Provider shall provide the Customer with determination of the acceptability for use of the model for a Generation Interconnection Request. In the event that the Transmission Provider is unable to complete the studies within 90 days of the execution of this Agreement, and receipt of the relevant materials which includes any relevant specifications and modeling data, the Transmission Provider shall notify the Customer and explain the reasons for the delay.

CONFIDENTIALITY

5. The Transmission Provider shall keep confidential all information provided to it by the Customer used in the performance of the study of the new model.
6. Customer acknowledges that, consistent with Part VI of the Tariff, the Transmission Provider may contract with consultants, including the Transmission Owners, to provide services or expertise in the study process and that the Transmission Provider may disseminate information to the Transmission Owners.

COST RESPONSIBILITY

7. The Customer shall reimburse the Transmission Provider for the actual cost of the studies. Customer shall supply an initial deposit of \$10,000, with the execution of this agreement, in order to fund initial studies. All deposit monies shall be fully refundable following payment of all charges incurred in the study of this model.

DISCLAIMER OF WARRANTY, LIMITATION OF LIABILITY

8. In analyzing and preparing the studies, the Transmission Provider, the Transmission Owner(s), and any other subcontractors employed by the Transmission Provider shall have to



rely on information provided by the Customer and possibly by third parties and may not have control over the accuracy of such information. Accordingly, NEITHER THE TRANSMISSION PROVIDER, THE TRANSMISSION OWNER(S), NOR ANY OTHER SUBCONTRACTORS EMPLOYED BY THE TRANSMISSION PROVIDER MAKES ANY WARRANTIES, EXPRESS OR IMPLIED, WHETHER ARISING BY OPERATION OF LAW, COURSE OF PERFORMANCE OR DEALING, CUSTOM, USAGE IN THE TRADE OR PROFESSION, OR OTHERWISE, INCLUDING WITHOUT LIMITATION IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE WITH REGARD TO THE ACCURACY, CONTENT, OR CONCLUSIONS OF THE NECESSARY STUDIES. The Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder. Neither this Agreement nor the studies performed hereunder are intended, nor shall either be interpreted, to constitute agreement by the Transmission Provider or the Transmission Owner(s) to provide any transmission or interconnection service to or on behalf of the Customer either at this point in time or in the future.

9. In no event will the Transmission Provider, Transmission Owner(s) or other subcontractors employed by the Transmission Provider be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, whether under this Agreement or otherwise, even if the Transmission Provider, Transmission Owner(s), or other subcontractors employed by the Transmission Provider have been advised of the possibility of such a loss. Nor shall the Transmission Provider, Transmission Owner(s), or other subcontractors employed by the Transmission Provider be liable for any delay in delivery or of the non-performance or delay in performance of the Transmission Provider's obligations under this Agreement. Without limitation of the foregoing, the Customer further agrees that Transmission Owner(s) and other subcontractors employed by the Transmission Provider to prepare or assist in the preparation of any Necessary Studies shall be deemed third party beneficiaries of this provision entitled "Disclaimer of Warranty/Limitation of Liability."

MISCELLANEOUS

10. Any notice or request made to or by either party regarding Agreement shall be made to the representative of the other party as indicated below.

Transmission Provider

PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403

Customer



Attn:	
Phone:	
Email:	

11. No waiver by either party of one or more defaults by the other in performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any other or further default or defaults, whether of a like or different character.

12. This Agreement or any part thereof, may not be amended, modified, or waived other than by a writing signed by all parties hereto.

13. This Agreement shall be binding upon the parties hereto, their heirs, executors, administrators, successors, and assigns.

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

Transmission Provider:

By:	Name:	Title	Date
	Printed Name of Signer:		

Customer:

By:	Name:	Title	Date
	Printed Name of Signer:		

ATTACHMENT #1

Generator Data

Add data to be used (Supply data under the form of the Impact Study Data Form through the PJM website as well as configuration information for the facility).

Attachment G-2: System Impact Study Data Form

Note:
This form is not to be used for submitting System Impact Study Datasheet. Data must be submitted through the PJM website: <http://pjm.com/planning/rtep-development/expansion-plan-process.aspx>

* Denotes Required Field

General Information

* Queue letter and position:	
* Interconnection customer name (company name):	
* Name of individual completing the form:	
* Email:	
* Phone:	
* Is this a change in data to a previously submitted impact data form for the queue position noted above?	<input type="checkbox"/> Yes <input type="checkbox"/> No

Point of Interconnection (POI)

* Connection type. Please select one: Existing substation Line tap/ new substation

If "Existing Substation" is selected specify the following:

* Specify existing substation name:	
* POI voltage:	KV

If "Line tap/ new substation" is selected specify line ends:

* Substation A (from):	
* Substation B (from):	
* Line voltage:	KV

* Total length of line:

Miles

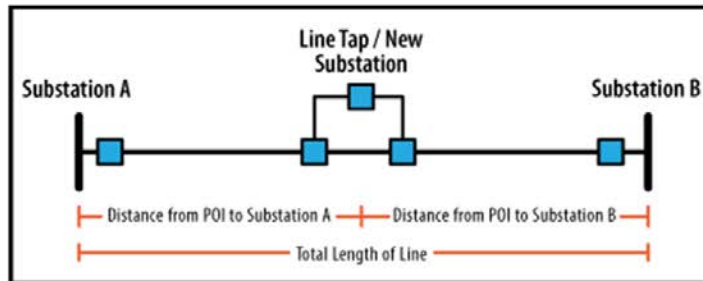
Please select one:

Distance from POI to Substation A

Miles

Distance from POI to Substation B

Miles



Work Being Performed

* Is this request a modification to an existing facility?

Yes No

If yes, explain in detail, how is the additional MW injection being obtained? Make sure to identify the components being subjected to work or improvements.

Illustrative examples include: (below are examples not including all possible responses)

- Generator ID being upgraded by rewinding or additional work such as...
- Auxiliary or station load being reduced by...
- New equipment being added to improve efficiency (e.g. measurement uncertainty recapture)
- Rotor replacement for unit ID resulting in ...
- Demonstrated capability of higher power output. No changes to power plant.

If no, provide description of facility

Project Capability



Provide Generating Facility Capability Pursuant to this Interconnection Request

	Summer	Winter
* Total net capacity output (CIR):	MW	
* Total net energy output (energy resource):	MW	
* Total gross energy of facility:	MW	
* Total auxiliary load of facility	MW	
Load related to the operations of the plant (e.g fans, pumps, etc)	MVAR	

* Where is the auxiliary load being connected? Please select one...

Low voltage side of the GSU
 High voltage side of the GSU
 Location other than the two options above

* If, other location is selected, provide additional comments on Aux Load:

* Station load	MW	
Load necessary to support facility of the plant	MVAR	

* Where is the Station Load being connected? Please select...

Low voltage side of the GSU
 High voltage side of the GSU
 Location other than the two options above

* If, other location is selected, provide additional comments on Aux Load:

Total Reactive Power Capability at Max Gross Energy Output

* Leading – Underexcited	MVAR	
* Lagging – Overexcited	MVAR	

For dynamic compensation contact PJM for a list of acceptable models.

Any additional comments related to the configuration above:

Synchronous Generator

The next section below pertains to synchronous generator data (e.g. Biomass, Coal, Diesel, Hydro, Methane, Natural Gas, Nuclear, Oil, etc). If you are not providing data for a synchronous generator, please proceed to Page 122.

Provide individual generator capability (All values requested here are for individual units)

* Machine ID (e.g. ST, CT, CT1, CT2, ST2, etc.):
Note: List all the machine IDs that these data corresponds (e.g. CT1, CT2).

--

* MVA base:

MVA

--

* Terminal voltage:

KV

--

* Nominal power factor:

--

* Unit maximum net capacity output (CIR):

MW

Summer

Winter

--	--

* Total gross energy of facility:

MW

--	--

* Unit reactive power capability at max gross energy output – leading (*Underexcited*):

MVAR

--	--

* Unit reactive power capability at max gross energy output – lagging (*Overexcited*):

MVAR

--	--

* Unit auxiliary load at max gross energy output:

MW

--	--

MVAR

--	--

* Where is the auxiliary load being connected?

- Low voltage side of the GSU
- High voltage side of the GSU
- Location other than the two options above

* If, other location is selected, provide additional comments on Aux Load:

--

Generator Parameters

All reactances and resistance values in PU on Machine MVA Base

* Combined turbine-generator-exciter inertia, H:
 $1 < H < 10$

kWs/kVA

--

* Speed damping coefficient, D:
 $0 \leq D < 3$

P.U.

--

Generator Saturation

* Generator saturation at 1.0 p.u. voltage, S (1.0):
 $0 < S1.0$

PU

--

* Generator saturation at 1.2 p.u. voltage, S (1.2):
 $S1.0 < S1.2$

PU

--

Unsaturated Reactances

* Direct axis synchronous reactance, Xd(i):
 $x_d < 2.5$

PU

--

* Direct axis transient reactance, X'd(i):
 $x'd < 0.5 \times x_d$

PU

--

* Direct axis sub-transient reactance, X''d(i):
 $x''d < x'd$

PU

--

* Quadrature axis synchronous reactance, Xq(i):
 $x_q < x_d$

PU

--

* Quadrature axis transient reactance, X'q(i):
 $x'q < x_q$

PU

--

* Stator leakage reactance, Xl:

PU

--

* Negative sequence reactance, X2(i):

PU

--

* Zero sequence reactance, X0(i):

PU

--

Saturated Reactances

* Saturated sub-transient reactance, $X''d(v)$:
 $x_d < 2.5$

PU	
----	--

Synchronous reactance, $X_d(v)$:
 $x'd < 0.5 \times x_d$

PU	
----	--

Transient reactance, $X'd(v)$:
 $X''d(v) < X''d(i)$

PU	
----	--

* Negative sequence reactance, $X_2(v)$:

PU	
----	--

* Zero sequence reactance, $X_0(v)$:

PU	
----	--

Resistances

* DC armature resistance, R_a :

Ohms	
------	--

* Positive sequence resistance, R_1 :

PU	
----	--

* Negative sequence resistance, R_2 :

PU	
----	--

* Zero sequence resistance, R_0 :

PU	
----	--

Time Constants

* Direct axis transient open circuit, $T'do$:
 $1. < T'do < 10.$

sec	
-----	--

* Direct axis sub-transient open circuit, $T''do$:
 $0.01667 < T''do < 0.2$

sec	
-----	--

* Quadrature axis transient open circuit, $T'qo$:
 $0.2 \leq T'qo \leq 1.5$

sec	
-----	--

* Quadrature axis sub-transient open circuit, $T''qo$:
 $0.01667 \leq T''qo \leq 0.2$

sec	
-----	--

* Armature three-phase short circuit, T_{a3} :
 $0.025 \leq T_{a3} \leq 0.1$

sec	
-----	--

Generator Step-up Transformer (GSU) Form

The next section below pertains to the GSU for the synchronous generator. Please complete all required information below.

* MVA base: MVA

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select... Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

	R	jX	X/R
* (a) High-side to low-side:	PU	<input type="text"/>	<input type="text"/>
* (b) High-side to tertiary:	PU	<input type="text"/>	<input type="text"/>
* (c) Low-side to tertiary:	PU	<input type="text"/>	<input type="text"/>

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>

Step size:

Any additional comments on the transformer?
(e.g. Specify machine ID)

PSS/E simulation information

The equipment models listed below are those available for use in PSS/E. Each model can have unique data requirements. The minimum modeling required for dynamic simulation is a generator model, and an exciter model. These must be identified / submitted by the Interconnection Customer.

The manufacturer of the equipment to be incorporated in the design of a facility should be able to provide the proper model or an equivalent for the Interconnection Customer to identify. If you cannot determine the exact PSS/E model, you must submit a Control/Block Diagram for the piece of equipment in question.

Generator Models

GENROE Round rotor generator model.

GENROU Round rotor generator model.

GENSAE Salient pole generator model.

GENSAL Salient pole generator model.

GENDCO Round rotor generator model with DC offset torque component.

GENCLS Classical generator model.

GENTRA Transient level generator model.

CIMTRI Induction generator model with rotor flux transients.

CIMTR3 Induction generator model with rotor flux transients.

Static Var Compensator (SVC) and Frequency Changer Models

CSVGNI SCR controlled static VAR source model.

CSVGN3 SCR controlled static VAR source model.

CSVGN4 SCR controlled static VAR source model.

CSVGN5 WSCC controlled static VAR source model.

CSVGN6 WSCC controlled static VAR source model.

FRECHG Salient pole frequency changer model.

If the model for the SVC to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Excitation System Models

An exciter model is a minimum modeling requirement for dynamic simulation.

Additionally, the exciter model in certain cases is needed to ensure that the unit is transiently stable.

PJM maintains the following model information:

EXDC2 1981 IEEE type DC2 excitation system model.
EXAC1 1981 IEEE type AC1 excitation system model.
EXACIA Modified type AC1 excitation system model.
EXAC2 1981 IEEE type AC2 excitation system model.
EXAC3 1981 IEEE type AC3 excitation system model.
EXAC4 1981 IEEE type AC4 excitation system model.
EXST1 1981 IEEE type ST1 excitation system model.
EXST2 1981 IEEE type ST2 excitation system model.
EXST2A Modified 1981 IEEE type ST2 excitation system model.
EXST3 1981 IEEE type ST3 excitation system model.
ESAC1A 1992 IEEE type AC1A excitation system model.
ESAC2A 1992 IEEE type AC2A excitation system model.
ESAC3A 1992 IEEE type AC3A excitation system model.
ESAC4A 1992 IEEE type AC4A excitation system model.
ESAC5A 1992 IEEE type AC5A excitation system model.
ESAC6A 1992 IEEE type AC6A excitation system model.
ESDCIA 1992 IEEE type DCIA excitation system model.
ESDC2A 1992 IEEE type DC2A excitation system model.
ESST1A 1992 IEEE type ST1A excitation system model.
ESST2A 1992 IEEE type ST2A excitation system model.
ESST3A 1992 IEEE type ST3A excitation system model.
EXPIC1 Proportional/integral excitation system model.
IEEETI 1968 IEEE type 1 excitation system model.
IEET1A Modified 1968 IEEE type 1 excitation system model.
IEET1B Modified 1968 IEEE type I excitation system model.
IEEET2 1968 IEEE type 2 excitation system model.
IEEET3 1968 IEEE type 3 excitation system model.
IEEET4 1968 IEEE type 4 excitation system model.
IEEET5 Modified 1968 IEEE type 4 excitation system model.

IEET5A Modified 1968 IEEE type 4 excitation system model.

IEEEXI 1979 IEEE type 1 excitation system model and 1981 IEEE type DC1 model.

IEEEX2 1979 IEEE type 2 excitation system model.

IEEEX3 1979 IEEE type 3 excitation system model.

IEEEX4 1979 IEEE type 4 excitation system model, 1981 IEEE type DC3 model and 1992 IEEE type DC3A model.

IEEX2A 1979 IEEE type 2A excitation system model.

SCRX Bus or solid fed SCR bridge excitation system model.

SEXS Simplified excitation system model.

If the model for the excitation system to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Prime Mover and Governor Models

The prime mover governor model is required to demonstrate long-term stability of the unit in response to frequency oscillations.

PJM maintains the following model information:

CRCMGV Cross compound turbine governor model.

DEGOV Woodward diesel governor model.

DEGOV1 Woodward diesel governor model.

GAST Gas turbine governor model.

GAST2A Gas turbine governor model.

GASTWD Woodward gas turbine governor model.

HYGOV Hydro turbine governor model.

IEESGO 1973 IEEE standard turbine governor model.

IEEEG1 1981 IEEE type 1 turbine governor model.

IEEEG2 1981 IEEE type 2 turbine governor model.

IEEEG3 1981 IEEE type 3 turbine governor model.

SHAF25 25 mass torsional-elastic shaft model.

TGOV1 Steam turbine governor model.

TGOV2 Steam turbine governor model with fast valving.

TGOV3 Modified IEEE type 1 turbine governor model with fast valving.

TGOV5 Modified IEEE type 1 turbine governor model with boiler controls.

WEHGOV Woodward Electric Hydro Governor Model.

WESGOV Westinghouse Digital Governor for Gas Turbine.

WPIDHY Woodward P.I.D. hydro governor model.

If the model for the governor system to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Power System Stabilizer Models

Power System Stabilizer must be added to the exciter circuits to force stability. However, devices such as Power System Stabilizers, as well as Excitation Limiters and Compensating devices, are less frequently applied, and are modeled if the equipment will be used.

PJM maintains the following model information.

IEEEEST 1981 IEEE power system stabilizer model.

IEE2ST Dual input signal power system stabilizer model.

PTISTI PTI microprocessor based stabilizer model.

PTIST3 PTI microprocessor based stabilizer model.

PSS2A 1992 IEEE dual input signal stabilizer model.

STAB1 Speed sensitive stabilizer model.

STAB2A ASEA power sensitive stabilizer model.

STAB3 Power sensitive stabilizer model.

STAB4 Power sensitive stabilizer model.

STBSVC WSCC supplementary signal for static VAR system.

ST2CUT Dual input signal power system stabilizer model.

Minimum Excitation Limiter Models

PJM maintains the following model information:

MNLEX1 Minimum excitation limiter model.

MNLEX2 Minimum excitation limiter model.

MNLEX3 Minimum excitation limiter model.

Maximum Excitation Limiter Models

PJM maintains the following model information:

MAXEX1 Maximum excitation limiter model.

MAXEX2 Maximum excitation limiter model.

Compensating Models

PJM maintains the following model information.

COMP Voltage regulator compensating model.

COMPCC Cross compound compensating model.

IEEEVC 1981 IEEE voltage compensating model.

REMCMP Remote bus voltage signal model.

Wind Farm

The next section below pertains to wind generator data (e.g. offshore wind and wind). If you are not providing data for a wind generator, please proceed to Page 126.

PJM has on file the manufacturer data sheets for the following Wind Turbines:

Acciona AW 1530 1.5 MW, 3.0 MW; Clipper C93 2.5 MW; Gamesa G8x/G90 2 MW; GE 1.5 MW, 1.6 MW, 2.5 MW, 2.75 MW, 4.0 MW; Generic Wind Model (WT3 and WT4) Mitsubishi MWT92/95 2.3 MW, Nordex N90 2.5 MW, N100 2.5 MW, N117 2.4 MW; Repower MM82 2.05 MW; Siemens 2.3 MW, 3.0 MW, 3.6 MW, 4.0 MW, 6.0 MW; Suzlon S88 2.1MW, S97 2.1 MW; Vestas V82 1.8 MW, V90 1.8 MW, 3.0 MW, V100 1.8 MW, V112 3.075 MW.

If the Interconnection Customer intends to install any of the turbines listed above, then that Interconnection Customer must only supply the information listed below which is applicable to a wind plant data request and which is accompanied by an asterisk. If an Interconnection Customer intends to install a turbine other than one (or more) of the models listed above, then all data which follows as being required by a wind plant will be required.

Wind Farm Parameters

* Specify manufacturer:	
* Specify model:	
* MW Value per turbine (nominal rating):	
* Number of wind turbines generators of the selected type:	
* MVA base:	MVA
* Terminal voltage:	KV
* Nominal power factor:	PU on MVA base
* Stator resistance, R1:	Ohms
* Saturated sub-transient reactance, X"d(v):	PU on MVA base



* Please select a Control Mode:

- Power Factor
- Voltage Control
- Other

* Voltage relays?

If yes, provide voltage relay settings:

Yes No

* Frequency relays?

If yes, provide frequency relay settings:

Yes No

* Additional wind farm compensation?

If yes, provide type of reactive compensation (e.g. fixed shunts, switchable shunt bank, dynamic):

Yes No

Wind Farm - Generator Step-up Transformer (GSU)

Please complete all required information below.

* MVA base:	MVA	<input type="text"/>
-------------	-----	----------------------

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select... Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

	R	jX	X/R
* (a) High-side to low-side:	PU	<input type="text"/>	<input type="text"/>
* (b) High-side to tertiary:	PU	<input type="text"/>	<input type="text"/>
* (c) Low-side to tertiary:	PU	<input type="text"/>	<input type="text"/>

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>
Step size:	<input type="text"/>
Any additional comments on the transformer? (e.g. Specify machine ID)	<input type="text"/>

Wind Farm – Main Transformer Form

Please complete all required information below.

* MVA base:	MVA	<input type="text"/>
-------------	-----	----------------------

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select... Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

	R	jX	X/R
* (a) High-side to low-side:	PU	<input type="text"/>	<input type="text"/>
* (b) High-side to tertiary:	PU	<input type="text"/>	<input type="text"/>
* (c) Low-side to tertiary:	PU	<input type="text"/>	<input type="text"/>

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>
Step size:	<input type="text"/>
Any additional comments on the transformer? (e.g. Specify machine ID)	<input type="text"/>

Inverter Based Parameters

The next section below pertains to inverter based generator data (e.g. solar and storage). If you are not providing data for an inverter based generator, please proceed to Page 129.

Note:

All inverter based projects greater than 30 MW must submit a dynamic model. Dynamic model may be requested for projects less than 30 MW depending on the area. To avoid delays, whenever available, please submit a dynamic model.

* Type of inverter based technology (e.g solar, storage, etc.):	
* Specify manufacturer of inverter:	
* Specify model:	
* MW Value per inverter:	MW
* Total number of inverters:	
* MVA Base per inverter:	MVA
* Terminal voltage:	KV
* Nominal power factor:	PU
* Nominal output current at full load per inverter:	Amps
* Maximum fault current output from the inverter:	Amps or PU
* How fast can the inverter be disconnected from the system subsequent to a fault?	Cycles

* Description of dynamic performance of the inverter during a fault. Please describe how the selected inverter will behave dynamically with respect to real power, reactive power and tripping points for voltage and frequency:

Examples: Constant real and reactive power injection during a fault. No tripping allowed. Fluctuations in real and reactive power depending on system conditions. Please submit dynamic model for an accurate representation.

* Is the inverter designed with Low Voltage Ride-Through (LVRT) capability? Yes No

* Voltage relays? Yes No

If yes, provide voltage relay settings:

* Frequency relays? Yes No

If yes, provide frequency relay settings:

Inverter Based - Generator Step-up Transformer (GSU) Form

* MVA base:	MVA	<input type="text"/>
-------------	-----	----------------------

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select...

Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

		R	jX	X/R
* (a) High-side to low-side:	PU	<input type="text"/>	<input type="text"/>	<input type="text"/>
* (b) High-side to tertiary:	PU	<input type="text"/>	<input type="text"/>	<input type="text"/>
* (c) Low-side to tertiary:	PU	<input type="text"/>	<input type="text"/>	<input type="text"/>

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>
Step size:	<input type="text"/>

Any additional comments on the transformer? (e.g. Specify machine ID)	<input type="text"/>
--	----------------------

Inverter Based – Main Transformer Form

Please complete all required information below.

* MVA base: MVA

Total Transformer Ratings (MVA) e.g. OA/FA1/FA2

* Rating 1:	MVA	<input type="text"/>
* Rating 2:	MVA	<input type="text"/>
* Rating 3:	MVA	<input type="text"/>

* Select transformer windings. Please select...

Two windings Three windings

Impedances (All Values in PU on Transformer MVA base)

* (a) High-side to low-side:

	R	jX	X/R
PU	<input type="text"/>	<input type="text"/>	<input type="text"/>
PU	<input type="text"/>	<input type="text"/>	<input type="text"/>
PU	<input type="text"/>	<input type="text"/>	<input type="text"/>

* (b) High-side to tertiary:

* (c) Low-side to tertiary:

Winding Voltages

* High-side:	KV	<input type="text"/>
* Low-side:	KV	<input type="text"/>
* Tertiary:	KV	<input type="text"/>

Winding connection Types (Delta, Wye, Wye Gnd, etc)

* High-side:	<input type="text"/>
* Low-side:	<input type="text"/>
* Tertiary:	<input type="text"/>
* Tap position:	<input type="text"/>
Off-nominal Turns Ratio:	<input type="text"/>
Number of taps:	<input type="text"/>
Step size:	<input type="text"/>
Any additional comments on the transformer? (e.g. Specify machine ID)	<input type="text"/>

Attachment Line Data

Please complete all required information below.



* Voltage level (kV):

KV

* MVA Base:

MVA

* Line length:

Miles

* Conductor type (e.g. ACSR, AAC, AAAC, ACAR, etc.):

* Total branch positive sequence impedance:

PU

R	jX
<input type="text"/>	<input type="text"/>

* Total branch zero sequence impedance:

PU

R	jX
<input type="text"/>	<input type="text"/>

* Total branch charging susceptance:

PU

Any additional comments on the line?
(e.g two identical parallel lines)

Attachment H: Generator Reactive Deficiency Mitigation Process

H.1 Scope

The mitigation process is to address a reactive deficiency of an existing synchronous generator caused by an increase of its output (capacity or energy) resulting in that the generator reactive capability cannot meet the existing PJM power factor requirements as stated in the Tariff.

The mitigation process and the associated business rules will also be applied to all new interconnection requests regarding an increase of capacity or energy to an existing generator.

The mitigation process is not intended for:

- Wind or non-synchronous generators,
- Existing generators not requesting an increase of capacity or energy,
- Previous requests for capacity or energy increases

The process is in compliance with the existing Tariff requirements and the associated business rules and does not require a change in the existing Tariff.

Reactive Deficiency Definition

A Reactive Deficiency is defined as the difference between the Mvar capability of a generator after the upgrade for meeting the PJM power factor requirements and the actual Mvar capability of a generator after the requested increase in capacity or energy.

For existing generators that do not have a signed FERC Proforma Interconnection Service Agreement (ISA), the Mvar capability before the upgrade is the grandfathered Mvar capability determined by PJM. For generators that have a signed ISA, the Mvar capability before the upgrade is determined by the Mvar for meeting the power factor requirements as stated at Part VI, Att. O, App. 2, Section 4.7.1 of the Tariff.

For the incremental MW increase, the corresponding power factor requirements can be calculated according to the requirements stated at Part VI, Att. O, App. 2, Section 4.7.1.2 of the Tariff. Hence, the Mvar capability of a generator after the upgrade for meeting the PJM power factor requirements is defined as the sum of the grandfathered Mvar capability or the Mvar requirements stated in the Tariff and the Mvar requirement corresponding to the incremental MW increase.

After the upgrade, the actual Mvar capability of the generator is the Mvar, defined by the generator's reactive capability curve, corresponding to the Maximum Facility Output of the generator before the upgrade plus the incremental MW increase.

The reactive deficiency, if any, is determined during the Feasibility and the System Impact Study phases of an interconnection request regarding an increase of capacity or energy to an existing generator. The Interconnection Customer will be notified of the deficiency and the proposed mitigation before the execution of the Construction or Interconnection Service Agreement.

Mitigation Process

Currently, the Tariff allows the Interconnection Customer, at its expense, to install power factor correction or other equipment at the generation plant to mitigate the reactive deficiency and to

enable the generator to meet the PJM reactive power design criteria during operation. (Tariff at Part VI, Att. O, App. 2, Section 4.7.3) If the Interconnection Customer fails to mitigate the reactive deficiency, PJM can request the affected Transmission Owner to install Static Var Compensator (SVC) or similar dynamic reactive devices, at the Interconnection Customer's expense in the form of a Reactive Deficiency Charge, to mitigate the identified reactive deficiency. A shunt capacitor application could be considered but its application will require PJM review on a case by case basis.

For a generator reactive deficiency less than 50 Mvar, the Reactive Deficiency Charge will be equal to the reactive deficiency (in Mvar) multiplied by the most recent average cost estimates (in \$/Mvar) for installing SVCs on the PJM system. There will be two SVC cost estimates to be developed and updated annually by PJM – one for installations at or above 230kV and one for installations below 230kV. The applicable deficiency charge is based on the voltage at the high side of the generator step up transformer. In the event that a shunt capacitor application is allowed, the charge will be based on the most recent cost of similar shunt capacitor installation.

For a generator reactive deficiency greater than or equal to 50 Mvar, the affected Transmission Owner will be responsible to provide either the cost estimate (in \$/Mvar) for installing a SVC in its system which will be used to calculate the Reactive Deficiency Charge or the cost estimate (in \$) of a specific SVC or SVCs necessary to mitigate the reactive deficiency as determined by PJM and the affected Transmission Owner in the System Impact Study.

Reactive Deficiency Charge Payments

The Reactive Deficiency Charges can be paid in cash or via a letter of credit. The collected charges will be used to fund reactive projects in the Transmission Owner's zone in which the Interconnection Customer's generator is located. The affected Transmission Owners shall be responsible to construct, own and maintain these reactive projects.

If the Reactive Deficiency Charge for an individual Interconnection Request is less than \$2M and is insufficient to fund a planned reactive project, PJM can choose to use the collected charge to provide partial funding to this project. Alternatively, PJM can hold the collected charges in an account until sufficient funds have been collected to fund the entire project.

If the Reactive Deficiency Charge for an individual Interconnection Request is more than the cost of a planned reactive project, PJM can choose to use the collected charge to fund this project and hold the remaining fund in cash (not to exceed \$2M) or in a letter of credit as a security for use to fund future reactive projects. These funds will be used as soon as a reactive upgrade has been identified. Alternatively, PJM can develop a different reactive project to be funded entirely by the collected charge.

If the Reactive Deficiency Charge is more than \$2M and a reactive project has not been developed, PJM will require the Interconnection Customer to provide a letter of credit for use to fund a reactive upgrade as soon as it has been identified.

Review of and Modification to the Mitigation Process

NERC standards require that PJM, as the Transmission Operator, shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and contingency conditions. PJM will continue to assess the reactive capability of the system and serve as the backstop to recommend modifications to the mitigation process and the associated business



rules when and if there are insufficient reactive resources on the system to maintain system reliability.

Annex 1: SCADA Requirements by Transmission Owner Region

	MW and Voltage Threshold for SCADA Requirement		Must match Legacy SCADA ¹	SCADA POINTS														
	Distribution	Transmission		Gen ² CB Control	PQ data ²	CB Status	Volts	TT Status	Amps	MW	MVAR	MWH	MVARH	Harmonics	Freq.	V Flicker	Sag & Swell	
PJM	All Capacity Resources, Energy Resources >10 MW and all Resources able to set LMP.	All Capacity Resources, Energy Resources >10 MW and all Resources able to set LMP.	No	No	No	No	No	No	No	No	Yes	Yes	Yes	Yes	No	No	No	No
AE	3MW & above	3MW & above	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
AP	case by case basis	All require full SCADA & RTU	No	No	Yes	Yes	Yes (3ph)	No	Yes (3ph)	Yes	Yes	Yes	No	Y-32 orders	No	Yes	Yes	Yes
AEP	generally > 2MW	All	No	Yes - trip only	Yes	Yes	No	No	No	Yes	Yes	Yes	No	No	No	No	No	No
BG&E	All	All	No	Yes - trip only	Yes	Yes	No	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No
ComEd	2.5MW & up if TT is req'd or 10MW & up	All	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Dayton	As determined by Dayton	As determined by Dayton	No	Yes	No	Yes	No	No	No	Yes	Yes	Yes	No	No	No	No	No	No
Delmarva	3MW & above	3MW & above	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
Dominion	If Local Light load to Gen MWs ratio < 5	3MW & above	No	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No
Duquesne	Case by case, all 5 MW & above	1 MW & above	Yes	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No	No
FE	case by case basis	All	No	Yes - trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No
ODEC	2 MW & above	2 MW & above	No	No	No	Yes	No	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No
O&R	1 MW & above	All	No	No	No	Yes	No	No	No	Yes	Yes	Yes	No	No	Yes	No	No	No
PECO	5 MW & above	5 MW & above	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No
PEPCO	All - case by case exceptions	All - case by case exceptions	No	Yes - Trip only	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No	No
PPL	2.5 MW & above	All - 69 kV & above	Yes	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No	No	No
PSEG	case by case basis	All	No	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No
UGI	1 MW & above	1 MW & above, and All 66 kV & above	Yes	Yes - Trip only	No	Yes	Yes (3ph)	No	Yes (3ph)	Yes	Yes	Yes	No	No	Yes	No	No	No

1 PPL and Duquesne (69kV and above) and UGI (1MW and above or 66kV and above) require that customer matches their company's SCADA equipment. SGIWG Internet option not permitted.
 2 May be generator CBs (interrupting devices) and/or main CB (interrupting device)
 3 May also require installation of Power Quality monitoring device

Revision History

Revision 20 (10/01/2017):

- Biennial Cover to Cover Review
- Updated name of manual from “Generation and Transmission Interconnection Process” to “New Services Request Process”
- Section 1 - Labeled image as new Exhibit 1
- Section 1.1 - Requirements for Generating Units
 - Provides clarification of Generating Units and participation in the PJM Markets
- Section 1.2 - Interconnections with municipalities, co-operatives, or non-PJM member electric distribution companies (EDC)
 - Provides clarification of generator requirements for participation in the wholesale market
- Section 1.3 - Interconnection Procedures for FERC Jurisdictional and Non- FERC Jurisdictional Facilities
 - Provides clarification on generators that wish to participate in the Wholesale market, but are connected to an EDC
- Section 1.12 - Consent to Assignments
 - This is a new section that clarifies transfer of ownership processes before and after commercial operation of a Generator
- Section 1.20 - Non-Queue Interconnection Service Agreements
 - This is a new section which provides guidance for existing Generators which require an ISA
- Section 1.21 - Serving Load as a Generator
 - Unless allowed under applicable state or local law, an entity is not permitted to serve another entity’s load. Station Power loads can be served between generators in a single portfolio.
- Section 2.1.2.1 - Site Control
 - Provides additional clarification on the requirements for site control
- Section 2.1.2.2 - Generation Interconnection Requests
 - Multiple requests behind the same Point of Interconnection
 - Fuel Change
 - Attachment Y applications
 - Attachment BB applications
- Section 2.1.4 - New Service Request deficiency reviews

- o Requires a reasonable on-service date based on Study(ies) timeline and construction schedule
- Table 2-2-1: System Impact Study costs
 - o Corrected tables
- Section 2.3.1 - Queue Priority and final agreement issuance and determination of security requirements for moving out of sequence
 - o Added a discussion regarding cost allocation for network upgrades and the prioritization among queue positions with allocations to a shared network upgrade.
- Section 2.4 - Types of Network and Local Upgrades
 - o Provides clarification for the various types of Network Upgrades
 - o Labeled image as new Exhibit 2
- Section 2.5 - Transfer of Capacity Interconnection Rights
 - o Describes the process for transferring existing CIRs
- Section 2.6 - Work Papers
 - o This section defines Work Papers and how they relate to the RTEP base case used for modelling New Services Requests
- Section 3.1.4 - Expedited and/or Combined Study Analysis
 - o This section provides clarification for the combined study process and how it applies to small Generators
 - o Labeled image as new Exhibit 3
- Section 4.1.2 - Interim ISA vs. ISA with Interim Rights
 - o This section describes the difference between advancing construction with an Interim ISA, and advancing the in service date of the Generator coming into service ahead of the base case study year.
- Section 4.1.3 - Security Requirements
 - o Provides clarification on the security requirements for an ISA, WMPA, or UCSA

Section 4.1.4 – Agreement Milestones

- Provide clarification on the required Agreement Milestones
- Labeled image as new Exhibit 4
- Section 4.2.1 - Option to Build
 - o Provides clarification on “Option to Build”
- Section 4.3 - Wholesale Market Participation Agreement (WMPA)
 - o Defines what a WMPA is
- Section 5.1- Behind the Meter Generation Projects

- o This section provides additional clarification of Behind the Meter Generation (BtMG) interconnections
- Removed reference to Alternate Queue in Sections 1.9 and 3.1.2
- Made changes to language to remove separate procedures for Network Upgrades with costs <\$5 Million in Attachment B, Sections B.2, B.3.1 and B.3.2

Revision 19 (11/01/2016):

- Revision 19 incorporates language changes associated with the Early Queue Submittal Task Force (EQSTF) recommendations.
- Updated Exhibit 1 and added Exhibit 2. Process Flow, and Process Flow and Timeline respectively.
- Attachment A was modified to reflect the changes to the Planning Flow Diagram. Attachment A-1, and A-2 were included to reflect an interim transition Queue, and final Queue as depicted in the Planning Flow Diagram. The final Process Flow Diagram A-2 will be effective April 1, 2017.
- Additional language was added to Section 1 describing the changes to the Queue Process.
- Major changes were made to sections 2.1.2 and 2.1.3 to reflect the Earlier Queue Submittal Task Force's (EQSTF) recommendations.
- Tables 2-1-1, 2-2-1, 3-1-1, 3-1-3 and 3-1-4 were renumbered and changed to reflect the new study deposit requirements per the EQSTF's recommendations
- Added Tables 2-2-2 – System Impact Study Expected Costs and 3.1.2 – Feasibility Study Expected Costs for Attachment N submitted Small Generation Interconnection Requests.
- Section 2.1.4 was updated to reflect the changes to the New Service Request deficiency reviews per the EQSTF's recommendations
- Section 4.2.4 was changed to reflect the updated timeline as shown in revised Attachment A, A-1, and A-2.

Revision 18 (01/28/2016):

- Added Section 2.1.5.1 to reflect the inclusion of Phase Angle Regulators in Transmission Interconnection Requests
- Updated Section 2 of Attachment B to include a reference to Multi Driver Approach projects
- Updated Section 3.1 of Attachment B to address changes associated with the study methodologies for Long Term Firm Transmission Service in the New Services Queue

Revision 17 (01/22/2015):

- Update Section 1.12.1 to move coordination of PJM impacts on MISO facilities from the facilities study phase to the impact study phase of study

- Update Section 5.3 – 5.3.2 to address changes which include specific requirements contained in the Tariff for to wind and non-synchronous generation facilities
- Update Attachment F and inserted Attachment F-1 to incorporate data requirements for a Generation Interconnection Feasibility Study that is consistent with current online forms
- Updated Attachment G and inserted Attachment G-2 to incorporate data requirements that must be submitted to ensure proper modeling of Interconnection Requests in the System Impact Study phase that is consistent with current online forms

Revision 16 (11/01/2014):

- Update Sections 1.12.1 and 1.12.2 to incorporate provisions for interim deliverability studies.
- Add Sections 1.12.1.1, 1.12.2.1, 1.14, 1.14.1, 1.14.2 to incorporate provisions for interim deliverability studies.
- Update Section 3 by adding Sections 3.1.1, 3.1.2 and updating Section 3.1.3 to incorporate provisions in accordance with FERC Order 792 for the pre-application process.

Revision 15 (04/17/2014):

- Insert Sections 1.12 and 1.13 to document provisions for the study of cross border impacts between MISO and PJM associated with Interconnection Requests and Transmission Service Requests
- Update Attachment B to be consistent with current practices and Tariff defined terms
- Update Attachments F & G with current list of dynamic models which PJM has utilized in studies

Revision 14 (02/01/2013):

- Insert Section 2.2.1.1 and Attachment G-1 to incorporate requirements for the study of new dynamic model prior to their use in the System Impact Study for a Generation Interconnection Request
- Update Attachment C

Revision 13 (8/23/2012):

- Made changes to Attachment H: Generator Reactive Deficiency Mitigation Process to include generation increases of 20 MW or less.

Revision 12 (05/22/2012):

- Made changes to Table 3-1: Small Generation Interconnection Process deposit requirements (Interconnection requests of 2 – 20MW) and Table 3-2: Small Generation Interconnection Process deposit requirements (Interconnection Requests of 2MW or less).

Revision 11 (05/22/2012):

- Revision 11 incorporates (1) language changes associated with the Interconnection Process Senior Task Force recommendations (2) language describing the calculation of Capacity Interconnection Rights being transferred to a new facility, and (3) minor language cleanup to provide additional clarity on existing process elements.

Revision 10 (04/05/2012):

- Revision 10 incorporates (1) increased detail regarding section 1.8 Changes to Existing or Proposed Generation and (2) minor language cleanup to promote consistency throughout Manual 14A.

Revision 09 (04/12/2011):

- Revision 09 incorporates (1) increased detail regarding Generator Power Factor Requirements, (2) a new Attachment H: Generator Reactive Deficiency Mitigation Process, and (3) a clarification to the interconnection cost allocation process.

Revision 08 (05/01/2009):

- Revision 08 incorporates (1) corrections and clarifications to items entered under revisions 06 and 07, (2) changes to the deposit requirements for the System Impact Study and Facilities Study phases of interconnection project development, and (3) modifies references to the PJM web site following the PJM web site redesign.

Revision 07 (1/15/2009):

- Revision 07 changes incorporate a description of the requirements associated with the submittal of site control in conjunction with the submission of an Interconnection Request for wind generation to be studied for interconnection in PJM. This change was produced as a result of recommendations from the Regional Planning Process Working Group. Additional revisions incorporate editorial corrections.

Revision 06 (08/08/2008):

- Material related to the Interconnection process has been split from Manual 14B and located here. General material introducing the Manual 14 Series has been relocated to a new draft under construction which will be called Manual 14. Manual 14 will be devoted to introductory material for the entire PJM Manual 14 series.
- The following Interconnection process material includes extensive revisions related to improvements to the Queue study processes and procedures pursuant to applicable FERC and stakeholder proceedings as well as an accumulation of ongoing “housekeeping” updates.

Revision 05 (06/07/06):

- Revision 05 includes text revisions to state that PJM Transmission Expansion Planning 1) accommodates requests for new interconnections and 2) identifies the need for transmission system equipment replacements and/or upgrades through probability risk assessment (PRA) analysis of bulk power transformers as an input to the

Regional Planning Process. Replaced references to “ECAR, MAAC and MAIN” with ReliabilityFirst,

- Revisions were made on page 6, 7, 11 and 12.

Revision 04 (10/01/05):

- Revision 04 includes text that has been amended to accommodate the following: (1) clarification of small generation procedures; (2) clarification of Project Manager and Client Manager roles; and (3) additional explanatory information on treatment of generator deactivations.

Revision 03 (10/01/04):

- Revision 03 includes text revisions to accommodate the following: (1) changes necessitated by compliance with FERC Order 2003 on Standardized Generator Interconnection Agreements and Procedures; (2) changes necessitated by integration with AEP, Dayton, Dominion and Duquesne; (3) capacity and energy unit status text clarification; and (4) recent process changes to address behind-the-meter generation and economic planning.

Revision 02 (12/01/03):

- Revision 02 includes changes to include the Merchant Transmission Interconnection process description; also, the role clarity diagram in Attachment B has been revised.
- Changed all references from “*PJM Interconnection, L.L.C.*” to “*PJM.*”
- Reformatted to new PJM formatting standard; Renumbered pages to consecutive numbering; Renumbered Exhibit numbers.

Revision 01 (02/26/03):

- Change manual title from “PJM Manual for Generation Interconnection Process Overview” (M14A) to “PJM Manual for New Services Request Process Overview” (M14A); also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02):

- This document is the initial release of the PJM Manual for ***Generation Interconnection Process Overview (M14A)***.
- Manual M14, Revision 01 (03/03/01) has been restructured to create four new manuals:
- M14A: “Generation Interconnection Process Overview”
- M14B: “Generation Interconnection Transmission Planning”
- M14C: “Generation Interconnection Facility Construction”
- M14D: “Generation Operational Requirements”