PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: ~~41~~XX

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Prepared by
Transmission Planning Department

1.1 Planning Process Work Flow

The Manual 14 series provides information regarding PJM's regional transmission expansion planning protocol (RTEPP) to complement planning provisions in the PJM Operating Agreement, Schedule 6 and the PJM Open Access Transmission Tariff (OATT), Attachment M-3 (Attachment M-3 Process). These agreements can be found on-line at http:// www.pjm.com/media/documents/merged-tariffs/oatt.pdf.

This ongoing process has continued to evolve since 1997, when PJM's RTEPP (codified in PJM's Operating Agreement, Schedule 6) was approved by the Federal Energy Regulatory Commission (FERC). Since that time, the process has been expanded and enhanced in response to member and regulatory input as documented in the Operating Agreement, Schedule 6, OATT, Attachment M-3 and the PJM Manual 14 series. The current PJM regional transmission expansion plan (RTEP) process includes ample opportunity for stakeholder input through frequent oral and written exchange of information and reviews via the Transmission Expansion Advisory Committee (TEAC) and PJM's three (3) Subregional RTEP Committees (Mid-Atlantic, Southern and Western).

PJM and PJM Transmission Owners' planning processes are incorporated in an 18-month overlapping planning cycle which begins in September of the previous calendar year and extends through a full calendar year to the February of the next calendar year. This overlapping planning cycle is illustrated in Exhibit 1 in this Manual.

The PJM planning process activities, culminating in PJM's annual ~~Regional Transmission Expansion Plan~~RTEP, constitute PJM's single, Order No. 890 compliant, transmission planning process. All PJM ~~Open Access Transmission Tariff (~~OATT ~~)~~ facilities are planned through and included in this open, fully participatory, and transparent process.

There are ~~four~~ three (3) planning paths that ultimately culminate in the PJM RTEP base case, also referred to as the planning model. Facilities identified in each path allow for the opportunity for early, full and transparent participation by interested PJM stakeholders. The ~~four~~ three paths include planning activities associated with: (i) ~~projects planned for reliability (including operational performance and FERC Form No. 715 criteria), (ii) economic and public policy planning~~Baseline Projects, (ii) Supplemental Projects; and (iii) ~~generation and transmission interconnection planning, and (iv) Supplemental Projects~~Customer-Funded Upgrades. Baseline Projects include projects planned for (i) reliability, (ii) operational performance, (iii) FERC Form No. 715 criteria, (iv) economic planning~~market efficiency projects~~ and (v) public policy ~~(~~planning (State Agreement Approach). Supplemental Projects refers to transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, FERC Form No. 715, ~~or~~economic criteria ~~and not~~or State Agreement Approach projects. Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process include those that expand or enhance the transmission system and could include needs addressing transmission facilities at the end of their useful life as determined in accordance with good utility practice. Customer-Funded Upgrades refer to Network Upgrades, Local Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VI and paid for by the Interconnection Customer or Eligible Customer or voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade

Request.

Planning of ~~Transmission Facilities under PJM's Operational Control~~Baseline Projects:

~~Reliability, operational performance, FERC Form 715, economic planning and public policy planning~~Baseline Projects are produced from PJM's planning cycle activities described in this manual, Operating Agreement, Schedule 6, and illustrated in Exhibit 1 in this Manual. PJM leads ~~this~~ the analysis and development of Baseline ~~projects~~ Projects related to reliability, operational performance, FERC Form No. 715 criteria and economic planning for all facilities 100 kV and above under PJM's operational control. These facilities are designated as Bulk Electric System (BES) facilities and are subject to the North American Electric Reliability Corporation (NERC) ~~requirements~~ standards and criteria for such facilities. The PJM analyses ensure compliance with NERC, PJM and any applicable Regional Entity~~regional~~ criteria (e.g. Reliability First (RF) or SERC Reliability Corporation (SERC)). In addition, the PJM-led analyses also include analysis of and solutions for transmission facilities with nominal voltages below 100kV to the extent they are under PJM's operational control (see http:// www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx. The TEAC and Subregional RTEP Committees provide the opportunity for stakeholders to engage in the PJM transmission planning process of such facilities, as described in this Manual.

In addition, for transmission facilities under PJM's operational control, the Transmission Owner may submit its local planning criteria in its FERC Form No. 715 filing. ~~Additionally, the Transmission Owner may, using its local planning criteria not submitted as part of its FERC Form No. 715 filing, to develop Supplemental Projects, as described below, in accordance with the Transmission Owners' OATT, Attachment M-3 Process or through additional processes adopted by an individual Transmission Owner, as applicable.~~

~~Planning of Transmission Facilities Not under PJM's Operational Control:~~

~~The analysis of OATT transmission facilities below 100kV and not under PJM operational control is led by the Transmission Owners using their local planning criteria or FERC Form No. 715 criteria, as applicable. This is appropriate as the Transmission Owner is responsible to oversee the operation, maintenance and planning of its local system. These transmission facilities typically provide only local transmission functions, *e.g.*, serving the customers in the nearby electrical vicinity. The Transmission Owner analysis ensures local facilities not under PJM's operational control meet NERC (if applicable) and local reliability criteria or the Transmission Owner's local planning criteria.~~

Transmission Owner Supplemental Projects:

Supplemental Projects ~~are defined in the Operating Agreement as~~refer to a transmission expansion or enhancement not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria and is not a State Agreement Approach project. ~~The~~ Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address local reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life as determined in accordance with good utility practice).

Pursuant to the Attachment M-3 Process, Supplemental Projects are presented through the TEAC (230 kV and above facilities) or the Subregional RTEP Committees (below 230 kV facilities) for review and comment in a three-part meeting process that includes at a minimum (i) an Assumptions Meeting, (ii) a Needs Meeting and (iii) a Solutions Meeting. The Subregional RTEP Committees' Solutions Meetings are followed by a round of comments before the Transmission Owners finalize the Supplemental Projects. The stakeholders are provided a final comment period before the Supplemental Project is included in the Local Plan. Supplemental Projects included in the Local Plan are provided to the TEAC and the PJM Board as informational before integrating the Supplemental Project into the RTEP base case. Supplemental Projects are not approved by the PJM Board. It should also be noted that prior to integrating a Supplemental Project into the RTEP base case PJM performs a "do no harm study" to evaluate whether a proposed Supplemental Project will not adversely impact the reliability of the Transmission System as represented in the planning models used in all other PJM reliability planning studies. Once PJM determines that the proposed Supplemental Project will not adversely impact the reliability of the Transmission System, the proposed Supplemental Project may be integrated into the RTEP base case. In this way, Supplemental Projects are subject to similar, open, transparent and participatory PJM committee activities, as are PJM RTEP Projects (comprising Regional RTEP Projects and Subregional RTEP Projects; see discussion of TEAC and Subregional RTEP Committees).

~~Changes to the Transmission Owners' systems due to a Supplemental Project are included in both PJM and Transmission Owners planning models for the applicable reliability studies conducted outside the Attachment M-3 Process. The Transmission Owners' planning of Supplemental Projects follows the sequence of steps set out in OATT, Attachment M-3. PJM will include in the activities associated with the model development for the next year's RTEP, which begins in September (as outlined above for the 18-month RTEP cycle), those Supplemental Projects included in the Local Plans submitted for incorporation into the PJM planning model in the July timeframe. Additionally, as part of those activities~~As part of the review of Supplemental Projects, PJM will determine if the Supplemental Projects might eliminate a baseline violation identified in the RTEP processes which may be in progress. PJM will also apprise the relevant Transmission Owner if an RTEP Project is identified which might alleviate the need for a Supplemental Project. Any changes to the need associated with a Supplemental Project or baseline project will also be discussed with the PJM stakeholders.

~~Interconnection p~~Planning for Customer-Funded Upgrades is performed through PJM's New Services Queue~~encompasses~~ and includes Network Upgrades, Local Upgrades or Merchant

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Network Upgrades identified pursuant to OATT Parts II, III and VI~~generation and merchant transmission requests for Interconnections, and rerates as well as requests for long-term firm transmission service~~. Studies of interconnection and transmission service requests and any resulting transmission modifications are posted to PJM's website in the project queue area (http://www.pjm.com/planning/generation- interconnection.aspx). In addition, any necessary transmission facility modifications are brought to the TEAC for presentation and stakeholder participation. Interconnection planning is discussed in more detail in Manual 14A.

1.2 TEAC and Subregional RTEP Committee and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of the Operating Agreement, Schedule 6. Additionally, in 2008, PJM began to facilitate more localized planning functions through the Subregional RTEP Committees.

The TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the development of the RTEP, from early assumptions-setting stages to discussion of criteria violations and/or identified system needs, review of recommendations for alternative solutions and then review and comment regarding the solutions incorporated into the RTEP base case.

The Subregional RTEP Committees allow more focused and meaningful stakeholder participation and attention to the subregional and local Transmission Owner issues. Currently, there are three PJM RTEP subregions: Mid-Atlantic, Southern and Western. When a Subregional RTEP Committee meeting is needed and scheduled, it generally will be implemented as a separate meeting for each subregion.

~~For administrative convenience, RTEP projects (i.e., baseline projects) are separated into Regional RTEP Projects (230 kV and above) and Subregional RTEP Projects (below 230 kV) (referred to collectively herein as "RTEP Projects"), as defined in the Operating Agreement, in order to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest.~~

~~Regional RTEP Projects and Supplemental Projects (230 kV and above) will be reviewed at the TEAC. Subregional RTEP Projects and Supplemental Projects (below 230 kV) will be reviewed at the applicable Subregional RTEP Committee. The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. For Regional and Subregional RTEP Projects, the TEAC and Subregional RTEP Committees follow the procedure set forth in the Operating Agreement, Schedule 6 specific to the TEAC and other applicable PJM committee procedures. For Supplemental Projects subject to Attachment M-3, the Attachment M-3 Process will apply.~~

~~PJM will facilitate meetings as necessary of TEAC and Subregional RTEP Committees to review Regional RTEP Projects, Subregional RTEP Projects and Supplemental Projects.~~

~~The TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the development of the RTEP, from early assumptions-setting stages to discussion of criteria violations and/or identified system needs, review of recommendations for alternative solutions and then review and comment regarding the solutions incorporated into the RTEP base case.~~

~~The Subregional RTEP Committees and any related meetings allow more focused and meaningful stakeholder participation and attention to subregional and local transmission issues. Currently, there are three PJM RTEP subregions: Mid-Atlantic, Southern and Western. When a~~

~~Subregional RTEP Committee meeting is needed and scheduled, it generally will be implemented as a separate meeting for each subregion.~~

All PJM stakeholders can participate in any or all subregional activities on a voluntary basis, with one exception. The exception is that the Transmission Owners that comprise each of the various subregions must participate in the Subregional RTEP Committee meeting that includes their area and each Transmission Owner must be present at the TEAC meeting where its Supplemental Projects are presented.

PJM will facilitate meetings as necessary of TEAC and Subregional RTEP Committees to review Regional RTEP Projects, Subregional RTEP Projects and Supplemental Projects. PJM, with stakeholder input, may initiate additional Subregional RTEP Committees meetings consistent with OATT, Attachment M-3 to review and address stakeholder questions or concerns regarding needs or proposed solutions, as may be necessary or beneficial. Separate local meetings or more localized reviews may also be held by individual PJM Transmission Owners in the event that the individual Transmission Owner decides that it is a more appropriate way to address local issues. In addition to their participation in the TEAC and Subregional RTEP Committees meetings, stakeholders can also provide written comments on the development of the RTEP. Written comments can be provided to PJM through the Planning Community on PJM.com.

For administrative convenience, RTEP projects (i.e., baseline projects) are separated into Regional RTEP Projects (230 kV and above) and Subregional RTEP Projects (below 230 kV) (referred to collectively herein as “RTEP Projects”), as defined in the Operating Agreement, in order to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest.

Regional RTEP Projects and Supplemental Projects (230 kV and above) will be reviewed at the TEAC. Subregional RTEP Projects and Supplemental Projects (below 230 kV) will be reviewed at the applicable Subregional RTEP Committee. The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. For Regional and Subregional RTEP Projects, the TEAC and Subregional RTEP Committees follow the procedure set forth in the Operating Agreement, Schedule 6 specific to the TEAC and other applicable PJM committee procedures. For Supplemental Projects subject to Attachment M-3, the Attachment M-3 Process will apply.

~~The review of all RTEP projects will be conducted at the TEAC and/or Subregional RTEP Committees. Such r~~Review of RTEP Projects and Supplemental Projects at the TEAC and/or Subregional RTEP Committees normally occurs during the February through August RTEP stakeholder analysis and review periods (see Exhibit 1). However, additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year will follow OATT, Attachment M-3 Process for inclusion in the RTEP.

Stakeholders will be provided the information necessary for participation in the discussions and evaluations, including: (1) the PJM and/or Transmission Owners models, criteria and assumptions that underlie transmission system plans, (2) the procedure to access the study information necessary to replicate the PJM and/or Transmission Owner planning studies and participate in the evaluation and discussion of the identified need, (3) information regarding the project proposed to address the identified need, (4) the current cost estimate for the project, and (5) a description of the proposed modifications to existing facilities that may be part of the project.

In addition, projects that originate through local Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned ~~Transmission Owner RTEP projects (including both~~Baseline and newly planned Supplemental Projects and Transmission Owner Initiated projects from past RTEP cycles that are yet to be placed in-service). This website will provide tracking information about the status of listed projects and planned in-service dates. It will also include information regarding criteria, assumptions and availability of study cases ~~related to local planning~~.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning (including Operational Performance and Public Policy Planning)

PJM's planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.**) This forecast includes** the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standard MOD-032, as well as Transmission Owners' assumptions included in their respective FERC Form No. 715. As necessary, PJM updates those models with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual's Attachments.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

1.3.2 Economic Planning

PJM will perform a market efficiency analysis each year, following the completion of the near-term reliability plan for the region. PJM's market efficiency planning analyses will utilize many of the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements' annual benefits and annual cost. The annual revenue requirement rate is used to determine the enhancements' annual cost. PJM will finalize the market efficiency analysis input assumptions soon after the development of the PJM load forecast that is generally available approximately in late January. Prior to finalizing, PJM will review the proposed assumptions at the PJM Transmission Expansion Advisory Committee. This review will provide the opportunity for stakeholder review of and input to all of the key assumptions that form the basis of the market efficiency analysis. In this way, PJM will facilitate a comprehensive stakeholder review and input regarding RTEP study assumptions. All final assumptions and analysis parameters will be presented to the TEAC for discussion and review and to the PJM Board for consideration.

1.3.3 ~~Transmission Owner Local Planning~~FERC Form No. 715

The Transmission Owner's process specific to ~~local planning~~the Transmission Owner's zone, including projects ~~required to~~that could address the end of useful life of existing facilities, may be memorialized as ~~local~~ Transmission Owner planning criteria under the Transmission Owner's FERC Form No. 715~~ or under OATT, Attachment M-3~~.

1.3.4 Supplemental Projects

Supplemental Projects are included in both PJM and Transmission Owners planning models for the applicable reliability studies conducted outside the Attachment M-3 Process, to the extent the Supplemental Project impacts the transmission system.

The Transmission Owners' planning of Supplemental Projects follows the sequence of steps set out in OATT, Attachment M-3. PJM will include in the activities associated with the model development for the next year's RTEP, which begins in September (see 18-month planning cycle illustrated in Exhibit 1 in this Manual), those Supplemental Projects included in the Local Plans submitted for incorporation into the PJM planning model in the July timeframe.

Additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year, and which are finalized after July, may be included in the base case if the inclusion of these projects would not disrupt analysis associated with the development of the RTEP violations.

1.4 RTEP Process Key Components

PJM's goal is to ensure electric supply adequacy and to enhance the robustness of energy and capacity markets. Achieving these objectives requires the successful completion of PJM's planning, facility construction and operational and market infrastructure requirements.

Key components of PJM's 15-year transmission planning process discussed in this Manual include:

1. Baseline reliability analyses:

    The PJM Transmission System ("PJM System") provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the Transmission System to serve all existing and projected long term firm transmission use including existing and projected native load growth as well as long term firm transmission service. RTEP baseline analyses include system voltage and thermal analysis, and stability, load deliverability, and generation deliverability testing. These tests variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability, thermal line loadings and voltage limits. Baseline reliability analyses are discussed in more detail in Section 2 and Attachment C.

~~2.1. Generation and transmission interconnection analyses:~~

~~All entities requesting interconnection of a generating facility (including increases~~

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~~to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. In addition to the baseline analyses discussed above, as resources or merchant transmission requests interconnection, deliverability in the local area of the request is restudied and updated. The generation and transmission interconnection process and deliverability testing procedures are discussed in Attachment C and Manual 14A. The evaluation of generation and merchant transmission interconnection requests is codified in the PJM Open Access Transmission Tariff (available on the PJM Web site at http://www.pjm.com/).~~

~~3.~~2. Economic analyses (Market Efficiency studies):

In addition to reliability based analyses PJM also evaluates the economic merit of proposed transmission enhancements. These analyses focus on the economic impacts of security constraints on production cost, congestion charges to load and other econometric measures of market impacts. PJM's market efficiency analyses are discussed in Section 2 of this Manual and Attachment E. PJM development of economic transmission enhancements is also codified under Schedule 6 of the PJM Operating Agreement.

~~4.~~3. Operational performance issue reviews and accompanying analyses:

Maintaining a safe and reliable Transmission System also requires keeping the transmission system equipment in safe, reliable operating condition as well as addressing actual operational needs. On an ongoing basis, PJM operating and planning personnel assess the PJM transmission development needs based on recent actual operations. This may lead to special studies or programs to address actual system conditions that may not be evident through projections and system modeling.

To ensure that system facilities are maintained and operated to acceptable reliability performance levels, PJM has implemented an Aging Infrastructure Initiative to evaluate appropriate spare transformer levels and optimum equipment replacement or upgrade requirements. This initiative, based on a Probability Risk Assessment (PRA) process, is intended to result in a proactive, PJM-wide approach to assess the risk of facility failures and to mitigate operational and market impacts. Section 2 of this manual provides further discussion of the PRA process.

~~5.~~4. FERC Form No. 715

Each Transmission Owner specifies reliability criteria it uses to evaluate system performance in its FERC Form No. 715 filing. As part of the RTEP process, PJM will identify system needs using each Transmission Owner's ~~local~~ planning criteria, ~~including~~ which could include end of useful life as determined in accordance with good utility practice and other asset management activities, reflected in the Transmission Owner's FERC Form No. 715.

~~6.~~5. Supplemental Project Planning

Transmission Owner may identify a need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria and is not a State Agreement Approach project. The PJM

Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address local reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements; or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life as determined in accordance with good utility practice.

6. ~~Generation and transmission interconnection~~Customer-Funded Upgrade analyses:

All entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. In addition to the baseline analyses discussed above, as resources or merchant transmission requests interconnection, deliverability in the local area of the request is restudied and updated. The generation and transmission interconnection process and deliverability testing procedures are discussed in Attachment C and Manual 14A. The evaluation of generation and merchant transmission interconnection requests is codified in the PJM Open Access Transmission Tariff (available on the PJM Web site at http://www.pjm.com/).

7. The Final RTEP Plan

Based on all of the requirements for firm transmission service on the PJM System, PJM ~~annually~~ develops an annual ~~Regional Transmission Expansion Plan~~RTEP to meet those requirements on a reliable, economic system development and environmentally acceptable basis.

Furthermore, by virtue of its regional scope, the RTEP process assures coordination of expansion plans across multiple transmission owners' systems, permitting the identification of the most ~~effective and~~ efficient or cost-effective expansion plan for the region. The RTEP ~~plan~~ developed through this process is reviewed by PJM's independent Board of Managers who has the final authority for ~~plan's~~ approval of the RTEP (except approval of Supplemental Projects) and implementation. The following Section 2 describes the PJM RTEP Process analysis.

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1.5 Planning Criteria

PJM and/or Transmission Owners' planning information, including models, criteria and assumptions, provided pursuant to Operating Agreement, Schedule 6 or OATT, Attachment M-3 must be adequate to allow stakeholders to replicate the results of planning studies.

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1.5.1 Reliability Planning

Stakeholders have the opportunity at a national level through the participatory standards development process of the North American Electric Reliability Corporation (NERC) to influence the industry planning criteria that form the basis of PJM's planning process (found at http://www.nerc.com/Pages/default.aspx.) NERC regional criteria development, applicable to PJM, is also open to stakeholder input through the open and participatory process of ReliabilityFirst Corporation (found at https://www.rfirst.org/standards/Pages/StandardsDocuments.aspx).

Additionally, regional and ~~local~~ Transmission Owner planning criteria that go beyond and complement the NERC ~~obligations~~ Reliability Standards can be created and incorporated into PJM planning through participation in PJM's Planning Committee and other related stakeholder processes (please refer to http://pjm.com/committees- and-groups/committees.aspx.) In this manner, PJM, as the independent planning authority, avails stakeholders full opportunity to participate in the planning process from assumptions setting to the final plan. The PJM annual regional plan is based on the effective criteria in place at the time of the analyses, including applicable standards and criteria of the NERC and the applicable regional reliability entity, the various Nuclear Plant Licensees' Final Safety Analysis

[1] The Reliability*First* Regional Reliability Corporation (RRC) for the PJM Mid-Atlantic and Western Regions (which replaced the former ECAR, MAAC and MAIN RRCs on January

Report grid requirements and the PJM and ~~local~~ Transmission Owner Reliability Planning Criteria (Attachment D). Section 2 details the specific criteria applicable to each transmission planning process study phase. Criteria are comparably applicable to all similarly situated Native Load Customers and other Transmission Customers.

1.5.2 Market Efficiency Planning

Market efficiency planning is an evaluation process that results in facilities planned to achieve economic efficiencies rather than an analysis that produces violations measured against criteria. This process compares alternative plans' cost effectiveness in improving transmission efficiency and produces RTEP recommendations from this process. The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's threshold test and bright line economic efficiency test. This test specifies that a proposed solution's savings must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test). Each of this process' elements, its underlying assumptions and its methods is described in more detail in the accompanying sections of this manual 14B and in Attachment E.

1.5.3 FERC Form No. 715 Planning

The Transmission Owner's local planning criteria may be included in its FERC Form No. 715 filing. These documents may include criteria governing the planning of upgrades to the transmission system, which is in addition to the PJM Planning criteria and may include information specific to a Transmission Owner's asset management activities.

1.5.4 Supplemental Project Planning

The criteria for Supplemental Projects (which could include criteria required to address end of useful life of existing transmission facilities as determined in accordance with good utility practice) are described by each Transmission Owner.

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Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

2.1 Transmission Planning = Reliability Planning + Market Efficiency+ FERC Form No. 715 + Public Policy + ~~Local Area~~Supplemental Project Planning

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead-time transmission needs on a timely basis.

Fundamentally, the Baseline reliability analysis underlies all planning analyses and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

1. Baseline reliability upgrades, discussed in this Section 2;
2. ~~Generation and transmission interconnection upgrades, discussed in Attachment B of this manual and Attachment B of Manual 14A~~Operational Performance issue driven upgrades, discussed in Section 2;

~~2.~~

3. Market efficiency driven upgrades, discussed in this Section 2;

~~4. Operational performance issue driven upgrades, discussed in this Section 2;~~

~~5.~~4. FERC Form No. 715 projects, discussed in Section 2;

~~6.~~5. Public Policy Requirements based elements via State Agreement Approach;

~~7.~~6. Supplemental Projects by a Transmission Owner, ~~including~~ which could include projects addressing the end of useful life of existing facilities addressed via OATT, Attachment M-3.

2.1.1 Multi-Driver Approach

In the event that a proposed project is driven by more than one of the above stated drivers, PJM can develop a Multi-Driver Approach Project, as defined in Schedule 6 of PJM's Operating Agreement by identifying a more efficient or cost effective solution that follows one of the following methods:

Proportional Multi-Driver Method: Combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project.

Incremental Multi-Driver Method: Expanding or enhancing a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.

2.1.1.1 Principles and Guidelines for New Service Requests as an input to Multi-Driver Approach

Customer-Funded upgrades, as identified in Attachment B of PJM Manual 14A may be incorporated into the Multi-Driver Approach Project per the Regional Transmission Expansion Plan. New Service Customers, other than those proposing Merchant Network Upgrades, have the option, but not obligation to participate in a Multi-Driver Approach Project, at the direction of PJM. The following principles and guidelines must be adhered to for a New Service Request wishing to participate in a Multi-Driver Approach Project:

1. The Multi-Driver Approach Project must be more cost effective as a whole, than the sum of the individual projects
2. New Service Customer has the option, but not the obligation to participate in a Multi-Driver Approach Project. The New Service Customer must execute an agreement committing to be financially responsible for its portion of the Multi-Driver Approach Project, the cost of which shall not exceed the cost of the incremental upgrade required as part of the New Service Request, unless agreed to by the sponsoring New Service Customer(s).
3. New Service Customer's participation in the Multi-Driver Approach Project shall not impact the New Service Customer's Queue Position.
4. Commencement of service for the New Service Customer's Customer Facilities may be impacted by the in-service date of the Multi-Driver Approach Project.
5. The following cost allocation rules will apply to Multi-Driver Approach Projects: Schedule 12 of the PJM Tariff for the component of the upgrade to be funded for reliability violations or operational performance, economic constraints and/or Public Policy Requirements; and Part VI of the PJM Tariff for the New Service Customer's portion of the Multi-Driver Approach Project.

2.1.2 Reliability Planning

Exhibit 1 shows the 24-month Reliability planning process used for the 15-year RTEP horizon. This 24-month planning process integrates the upgrades noted above with information transparency, stakeholder input and review and PJM Board of Manager approvals. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month planning process is made up of overlapping 18-month planning cycles (Refer to Exhibit 1) to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. Consistent with the requirements of the NERC TPL Reliability Standards the 24-month planning process includes both near- term (years one through five) and long-term (years six through fifteen) assessments of the transmission system as described below.

The first step in the process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at Transmission Expansion Advisory Committee and Subregional RTEP Committees meetings. A series of power-flow base cases are then developed based on the assumptions. The yearly series of cases include the latest information and assumptions available related to load, resources and transmission topology. A new 5-year base case is developed for near-term baseline reliability analysis. Base cases for retool analyses of years closer than 5-years are developed as required.

In addition to these near-term base cases additional power-flow base cases are developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring a longer time to develop. These longer lead time projects generally provide a more regional benefit. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in year eight. As noted in Exhibit 1, this 8-year out base case is updated and retooled at the start of the second year of the 24-month planning cycle (i.e. at that point a 7-year out base case), with additional criteria analysis being run to validate the findings from the analysis that was conducted during the first year of the 24-month planning cycle.

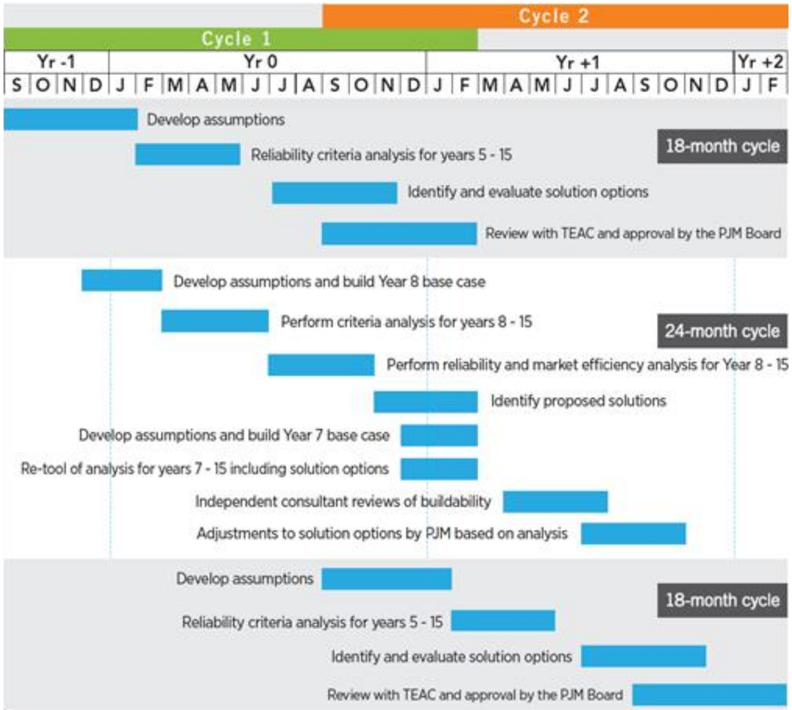

Exhibit 1: 24-Month Reliability Planning Cycle

The scope of the near-term baseline analysis that is completed as part of each 12-month planning cycle includes an exhaustive review of applicable reliability planning criteria on all BES facilities as described in section 2.3 of this manual. As noted above, PJM typically performs this near-term analysis on a 5-year out base case. Retool analyses of previous near-term assessments are also completed, as required. Any identified criteria violations are reviewed with stakeholders throughout the planning process. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC and/or Sub-regional RTEP Committee as applicable, and submitted to the PJM Board of Managers for approval. Through this planning process, a baseline system without any criteria violations is developed for the near-term (i.e., 5-year baseline). This baseline system, without any criteria violations, is then used for subsequent interconnection queue studies.

Long-term planning is also completed as part of the development of the RTEP to identify solutions to planning criteria violations that require longer lead times to implement. As part of the 24-month planning cycle PJM initially develops an 8-year out base case that is used to evaluate planning criteria for the long-term planning horizon. Long term criteria analysis is completed on this base case during the first year of the 24-month cycle. A combination of a full AC power flow solution and linear analysis, as described in this manual, is used to determine the loading on facilities for years 8 through 15. Violations and proposed solutions to address them are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 2, during the second year of the 24-month planning cycle, the base case used for the long-term analysis during the first year (i.e., now year 7) is updated to reflect the latest assumptions about load, generation, DR, EE, and transmission topology. Long term criteria analysis is completed on this base case during the second year of the 24-month cycle. A combination of a full AC power flow solution and linear analysis, as described in this manual, is again used to determine the loading on facilities for years 7 through
15. Potential violations identified during the first year are validated and the proposed solutions to address those violations are refined during the second year of the 24–month planning cycle. An independent consultant may be used to develop an independent cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses, including potential violations and their solutions, are reviewed with the TEAC throughout the 24-month planning process. Ultimately, any required long-lead time solutions that are identified through this planning process are presented to the PJM Board of Managers for approval.

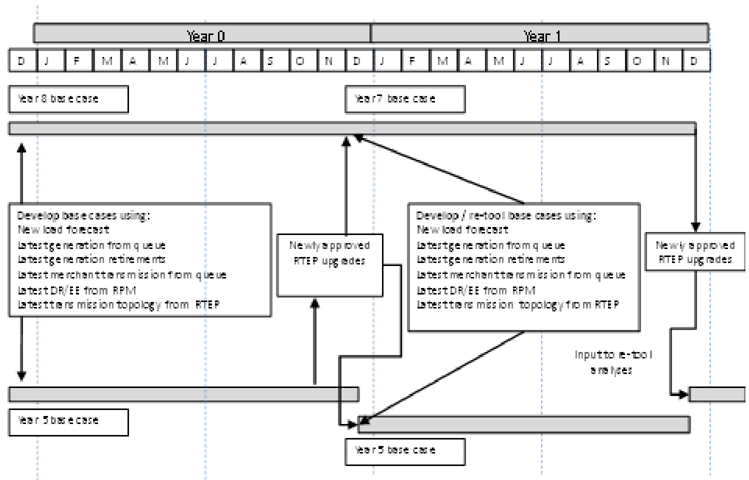

Exhibit 2: Base Case Development

2.3.1 Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, incorporation of the most recently finalized Local Plans and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

2.3.15 Maximum Credible Disturbance Review

The maximum credible disturbance review, identifies extreme events as defined in Table 1 of NERC Standard TPL-001-4, and assesses their impact on system reliability. If the initial analysis shows cascading caused by the occurrence of extreme events, PJM will perform an evaluation of possible action designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s). This can include a stability analysis of the area and an evaluation of possible actions to reduce the likelihood of the event or mitigate the consequences and impacts on the system.

PJM will also assess the impact of extreme events using stability analysis. Extreme events contained in Table 1 of NERC TPL-001-4 that produce more severe impacts shall be identified and a list created of those events will be maintained and distributed to the appropriate entities. The rationale for those contingencies selected for evaluation shall be available as supporting information. If the initial analysis shows cascading by the occurrence of extreme events, PJM will perform an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

2.8 Evaluation of End of Useful Life Issues

For each transmission need identified pursuant to FERC Form No. 715 or other Transmission Owner planning criteria addressing the end of useful life of an existing facility, each Transmission Owner should provide information, to the extent available, that supports the need for the project consistent with the Transmission Owner's planning criteria in accordance with the RTEP process or Attachment M-3 Process, as applicable.