FERC ADVANCE NOTICE OF PROPOSED RULEMAKING 2021:

TRANSMISSION PROJECT DEVELOPMENT TRANSPARENCY AND COST CONTROL PROCEDURES

PREPARED FOR:
DEVELOPERS ADVOCATING TRANSMISSION ADVANCEMENTS (DATA)

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TABLE OF CONTENTS

SECTION 1:

EXECUTIVE SUMMARY

Existing Oversight Measures for Transmission Transparency and Cost Control

The value of electric transmission is significant and well documented. Transmission infrastructure provides customers with a reliable and resilient flow of power, integrates diverse and cost-effective energy resources, enables production cost savings, reduces amounts and costs of planning reserve margins, and increases competition among supply resources for the benefit of customers.[1] As part of its Advance Notice of Proposed Rulemaking (ANOPR) proceeding, the Federal Energy Regulatory Commission (FERC) has recognized the significant value provided by transmission system expansion and seeks to promote effective regional and interregional transmission planning. At the same time, FERC is evaluating various means of providing oversight over the transmission development process to ensure consumer protection and cost-effective investment.

To inform the Commission's decision-making, this report provides a brief review of existing transparency and cost control promoting measures in selected Regional Transmission Organization (RTO) and Independent System Operator (ISO) regions. These measures vary by region, and this paper does not advocate for a single, unified approach for all regions. Instead, this paper seeks to demonstrate that there are multiple existing pathways that offer consumer protections that are independent from competitive bidding procedures under FERC Order No, 1000 (herein referred to as Order No. 1000 competitive bidding). While these procedures are often applied to projects subject to Order No. 1000 competitive bidding, they are also applied more broadly to other project classes and non-competitive projects. This indicates that Order No. 1000 competitive bidding is not a necessary precondition for transparency and cost control, and that traditional regulatory approaches may offer a more streamlined path to achieving these important goals.

Existing transparency measures in RTOs and ISOs include requirements for cost tracking, regularly updated status reports, and requirements to explain projected cost variances. Procedures that directly promote cost discipline include project re-evaluation for certain project classes based on established variance "bandwidths" and/or restrictions on recovery for certain cost overruns. Procedures designed to track cost variances can themselves promote cost discipline, while re-evaluation and cost containment measures can effectively protect customers from unreasonable cost increases while ensuring that beneficial projects are developed in a timely manner.

These processes facilitate the development of cost-effective transmission solutions. Importantly, they also provide an open and transparent means by which project costs are estimated, tracked,

1 *See e.g.*, Edison Electric Institute, Smarter Energy Infrastructure: The Critical Role and Value of Electric Transmission (March 2019).

managed, and contained during the development process. In most cases, these provisions are not unique to transmission projects that are subject to an Order No. 1000 competitive bidding process, although they are often applied in the Order No. 1000 competitive bidding context.

Instead of focusing on Order No. 1000 competitive bidding, stakeholders seeking transmission build-out efficiency would be well-served to focus attention on more traditional regulatory approaches already in place in many RTOs and ISOs. Arguably, Order No. 1000 competitive solicitations have not been as successful as hoped by the FERC, and while an effort to understand why this has occurred may be warranted, it cannot be the focal point in achieving the FERC's transmission development and consumer protection objectives. The timely development of transmission is critical for meeting clean energy goals and improving system resilience. Traditional regulatory mechanisms are likely the most efficient way to ensure that needed transmission is developed and the costs associated with transmission development are prudently incurred.

SECTION 2:
ISO NEW ENGLAND

Transmission Planning Overview

Planning Procedures

ISO New England (ISO-NE) is responsible for the planning of the pool transmission facilities (PTF) portion of the New England transmission system, including transmission facilities owned by Participating Transmission Owners (PTOs), which ISO-NE operates. Each PTO is responsible for administering the local system planning (LSP) process pertaining to its own (non-PTF) system and coordinating its efforts with ISO-NE.[2] In general, PTF are networked transmission facilities. Non-PTF are generally radial facilities or upgrades developed solely to meet local planning needs. The vast majority of transmission facilities in New England are PTF.

ISO-NE develops long range plans pursuant to Attachment K of its Open Access Transmission Tariff (OATT or Tariff) for the region's networked transmission facilities to address future system needs over a ten-year planning horizon. The transmission planning study process begins by developing a study scope and identifying all key inputs for conducting a Needs Assessment to determine the adequacy of the power system, as a whole or in part, to maintain the reliability of the existing facilities while promoting the operation of efficient wholesale electric markets in New England. ISO-NE conducts Needs Assessments to determine whether PTF upgrades are required in a given study area. Needs Assessments go through a development process where the scope, assumptions, and results are reviewed with the Planning Advisory Committee (PAC) at various points. If any reliability criteria violations are found as the result of a Needs Assessment, the needs are deemed to be either time-sensitive or not based on when the identified violation is expected to occur.

Proposed transmission system solutions are evaluated by ISO-NE to identify solutions for the region that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet the needs identified in a Needs Assessment. These study efforts may be in the form of a Solutions Study or a competitive solicitation, primarily depending on whether ISO-NE forecasts that a solution is needed to solve reliability criteria violations in three years or less from the completion of a Needs Assessment (i.e., time-sensitive).[3] If the need is not time-sensitive, the project is bid competitively.

ISO-NE publishes the Regional System Plan (RSP), or the long-term power system plan, on a biannual basis. There are a number of different types of other planning studies conducted in New England to

2 ISO-NE Transmission Planning Technical Guide, Section 1.1.
3 ISO-NE Transmission Planning Process Guide, Section 2.3.

assess or reflect the capability of the transmission system.[4] The standards, criteria and assumptions used in planning studies by all ISOs/RTOs are guided by a series of reliability standards and criteria, including the North American Electric Reliability Corporation (NERC) Reliability Standards and Northeast Power Coordinating Council (NPCC) standards and criteria. The current standards, criteria and assumptions used in various transmission planning studies in New England can be found in the Transmission Planning Technical Guide published by ISO-NE.

Stakeholder Engagement

All planning study efforts are discussed with the Planning Advisory Committee (PAC), and opportunities are provided for comments beginning with the draft scope of work and continuing through the posting of final reports.[5] Study power flow models are posted on the ISO-NE website and available to all PAC members subject to provisions to safeguard Critical Energy Infrastructure Information (CEII).

PAC meetings are public, and any entity can designate a member to the PAC. This includes any New England Power Pool (NEPOOL) participant representatives, representatives of government and/or local communities, state agencies, including those participating in the New England Conference of Public Utilities Commissioners (NECPUC), retail customers and public interest groups. Stakeholders are expected to actively participate in the PAC process by attending meetings, commenting on posted study scopes and reports and otherwise providing useful comments on the process. ISO-NE will consider all comments received from stakeholders during the PAC and respond in writing to specific suggestions. Members of the NEPOOL Reliability Committee (RC) also review Transmission Cost Allocation applications (TCA Applications, as described in more detail below) for projects in development.[6]

The PAC periodically provides input and feedback to PTOs concerning the development of their LSPs. Each PTO will present its respective LSP to the interested members of the PAC for advisory stakeholder input at least once per year. Each PTO's LSP will include transmission system plans for Non-PTF that are not incorporated into the RSP planning process.[7]

Transmission Solution Evaluation

ISO-NE coordinates with the PTOs and the PAC in developing and reviewing Needs Assessments and developing regulated and competitive transmission solutions. To use Solution Studies (i.e., non-competitive) rather than the Competitive Process for transmission needs, ISO-NE must demonstrate a time-sensitive need (i.e., needed for reliability within three years) and provide a full and supported

[4] ISO-NE Transmission Planning Technical Guide, Section 1.3.
[5] ISO-NE Transmission Planning Process Guide, Section 2.3.
[6] ISO-NE Transmission Planning Process Guide, Section 2.5.
[7] ISO-NE Transmission Planning Process Guide, Section 6.5.

written description explaining the decision to use a Solutions Study to the PAC.[8][9] For reliability needs that are not deemed time-sensitive, and for all market efficiency projects, the ISO-NE undertakes a competitive solicitation process.

Project Development Transparency

Project Cost Reporting

Project costs for both transmission expansion projects and asset condition projects are reported to stakeholders and ISO-NE three times per year via the RSP project list and the asset condition list.[10] These updates are reviewed with the PAC, including the major drivers of significant project cost changes.

Application / Evaluation Procedures

Through the TCA Application process, ISO-NE reviews all projects with costs in excess of $5 million to determine whether the project costs qualify for recovery through regional transmission rates. ISO-NE's Planning Procedure No. 4 provides an Applicant with guidelines and forms for preparing a TCA Application with the necessary information and analysis of the project, for use by the ISO and the RC. In particular, project costs are reported in a standardized format by all PTOs. Approval of a TCA Application by the ISO informs an Applicant of the approved Project costs that may be included in Pool-Supported PTF revenue requirements subject to the terms and conditions in the OATT.[11]

If the total estimated PTF portion of a project is less than $5 million, a TCA Application is not required unless actual costs exceed $5 million, or there is a potential that significant localized could be incurred. This review process also does not pertain to generator interconnection related upgrades; elective transmission upgrades; local benefit upgrades; recovery of localized costs; and merchant transmission facilities or their interconnection.[12]

Reporting Requirements

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8 ISO-NE Transmission Planning Process Guide, Section 2.7.1.

9 The Commission recently examined ISO-NE's implementation of the exemption for immediate need reliability projects and found that the record in that proceeding did not support a finding under Federal Power Act section 206 that the provisions in the ISO-NE Tariff containing the immediate need reliability project exemption are unjust, unreasonable, or unduly discriminatory or preferential. *ISO New England, Inc.*, 171 FERC ¶ 61,211 (2020). Further, the Commission found it unnecessary to impose additional criteria on the immediate need reliability exemption. *Id.*at PP 22-23.

10 https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.

11 ISO-NE Planning Procedure No. 4, Section 1.0.

12 ISO-NE Planning Procedure No. 4, Section 1.1.2. and Section 1.1.3.

A completed TCA Application along with supporting documentation is required to be submitted electronically to ISO-NE, who then collects, distributes, and creates a permanent record of the application. ISO-NE then notifies the applicant (TCA Applicant) if additional information is required.

There are five categories of project reporting guidelines in the planning procedures with different documentation detail requirements (ranging from no analysis for exempt projects to full costs analyses of transmission alternatives). The documentation detail required varies based on the total estimated PTF portion of the cost of the project, with progressively more and detailed information required. There is also more stakeholder review depending on the complexity/cost of the project.[13]

The TCA Applicant has an ongoing responsibility to update any TCA Application when additional information relevant to review of the TCA Application becomes available prior to the RC review and issuance of the ISO-NE's written findings and determination.[14]

For all non-exempt categories of projects, the RC reviews the TCA Application and makes a recommendation to ISO-NE regarding whether the proposed project costs should be included in the Pool-Supported PTF revenue requirements. Depending on the complexity of the project, there are a minimum number of introductory meetings required before action by the RC can be requested.[15] ISO-NE may also seek additional information from the applicant before or after RC or PC action but prior to making its decision.[16] For non-exempt projects where the required recommendation is received, the ISO will then issue the TCA Applicant its written findings and determination on the project. For projects that are $200 million or more, ISO-NE provides draft written findings and allows a 30-day comment period before issuing written findings and determination.[17] If the TCA Applicant disagrees with ISO-NE's written findings and determination, it can dispute the determination in a formal written notice to ISO-NE.[18] In 2020, for example, there were approximately fifty TCA Applications submitted to ISO-NE.[19]

Project Cost Discipline

Cost Evaluations

ISO-NE, with advisory input from the RC, considers the reasonableness of the proposed design and construction method with respect to: (a) good utility practice; (b) current engineering design and construction practices in the area in which the project is proposed to be built/is being built; (c)

13 ISO-NE Planning Procedure No. 4, Section 1.5.
14 ISO-NE Planning Procedure No. 4, Section 1.6.1.
15 ISO-NE Planning Procedure No. 4, Section 1.5.
16 ISO-NE Planning Procedure No. 4, Section 1.8.1.
17 ISO-NE Planning Procedure No. 4, Section 1.5.
18 Planning Procedure No. 4, Section 1.11.
19 As tracked here: https://www.iso-ne.com/static-assets/documents/2018/02/tca_application_status.pdf Tally includes multiple applications tracked within a single tracking row.

allowance for appropriate expansion and load growth; (d) alternate feasible and practical transmission alternatives; and (e) the relative costs, operation, efficiency, reliability and timing of implementation of the project.[20]

In determining whether there are localized costs, the ISO considers, with the advisory input of the RC, the following list of factors:

1. Costs of construction including all costs associated with rights of way, easements and associated real estate.
2. Assessment of the schedule or in-service date of the project from an engineering and construction standpoint rather than from the standpoint of potential delays in local or state siting.
3. Relative reliability and operational impacts of the project as compared to alternatives considered.
4. Costs associated with operation and maintenance of the proposed design and alternatives, including consideration of whether the proposed design is consistent with Good Utility Practice.
5. Costs of related and long-term congestion impacts, if any, of each proposed PTF and Non-PTF design alternative, including costs related to outages associated with construction.
6. The proposed design's fit into reasonable future expansion plans, including the RSP.
7. Consistency with current engineering, design, and construction practices in the area.[21]

Cost Sharing & Cost Allocation

ISO-NE, with advisory input from the RC, determines whether there are localized costs to be excluded from PTF revenue requirements. Similarly, the ISO may identify additional costs that are required as a result of local or state regulatory or legislative requirements (e.g., if the siting approval necessitates a design change) upon a demonstration from the TCA Applicant.[22]

Variance Analysis

A TCA Applicant who has already received approval of a TCA Application must notify both the RC and ISO-NE if either: (i) costs have exceeded or are anticipated to exceed 10% of the amount determined by ISO-NE to be included in pool-supported PTF costs; (ii) costs have decreased or are anticipated to decrease by 10% of the amount determined by ISO-NE to be included in pool-supported PTF costs; or (iii) there is a material change in design of the project. In the case that pool-supported PTF costs have decreased by 10% or more, a revised TCA Application does not need to be filed but information must be provided to ISO-NE and the RC in a timely manner, identifying and explaining the cost variance against the original TCA Application estimate.[23]

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[20] Planning Procedure No. 4, Section 1.6.2.2.
[21] ISO-NE Planning Procedure No. 4, Attachment A.
[22] ISO-NE Planning Procedure No. 4, Section 1.6.3.
[23] ISO-NE Planning Procedure No. 4, Section 1.10.

Re-evaluation Procedures

Costs associated with a variance analysis are excluded from the pool-supported PTF until the cost review process in Planning Procedure No. 4 has been followed and ISO-NE accepts the change in costs following review and recommendation by the RC.[24]

[24] ISO-NE Planning Procedure No. 4, Section 1.10.

SECTION 3:

MIDCONTINENT ISO

Transmission Planning Overview

Overview

The Midcontinent ISO (MISO) Business Practice Manuals (BPMs) provide information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. BPM No. 20 covers the processes for transmission planning in MISO. It is comprehensive and covers planning studies (cyclical and non-cyclical), project initiation and selection. The bottom-up and top-down planning functions repeat on a regular cycle, with a MISO Transmission Expansion Plan (MTEP) report produced annually.[25] BPM 20 describes three general categories of transmission projects – bottom-up projects, top-down projects, and externally driven projects. Bottom-up projects include transmission projects classified as other projects and baseline reliability projects (Baseline Reliability Projects).

Top-down projects include market efficiency projects (MEPs) and multi-value projects (MVPs). Top-down projects also include subregional and regional projects developed solely by the MISO planning process as well as interregional projects. Regional or subregional top-down projects that are ultimately classified as Market Efficiency Projects or MVPs are cost shared per provisions in the Tariff. Externally driven projects are projects driven by needs identified outside of the MISO MTEP planning process, such as an interconnection needs.

Within these broad categories, the MISO tariff defines additional projects classifications based on need-driver other criteria. These projects categories determine the resulting cost allocation and competitive process applicability.

- **Baseline Reliability Projects** Baseline Reliability Projects are network upgrades needed to comply with NERC reliability standards and regional reliability standards to maintain reliability while accommodating the ongoing needs of market participants and transmission customers. These projects may consist of a number of individual facilities that in the judgment of the transmission provider constitute a single project for cost allocation purposes.
- **Market Efficiency Projects** Project benefit evaluations are required to include benefits for the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year. If the project is eligible for competitive transmission planning, MISO will estimate costs applied in the benefit to cost ratio using professional judgment informed by publicly available information. A benefit to cost ratio test is used to evaluate a proposed Market Efficiency Project. Only projects that meet a benefit to

25 MISO BPM 20, Section 2.2.2.

cost ratio of 1.25 or greater are included in the MTEP as a Market Efficiency Project and be eligible for regional cost sharing. The benefits of the project and the cost allocations is presented to the MISO Board for approval.[26]

- **Multi-Value Projects –** MVPs consist of one or more network upgrades that address a common set of transmission issues. The primary purpose of an MVP is to enable cost sharing of projects that are regional in nature and developed to enable compliance with public policy requirements and/or to provide economic value. An MVP must be developed through the MTEP process, must provide multiple types of economic value across multiple pricing zones with a total MVP benefit-to-cost ratio of 1.0 or higher, and meet a number of other criteria. MVPs are evaluated as part of a portfolio of projects whose benefits are spread broadly across the footprint. The transmission project must be evaluated through the MISO planning process and approved for construction. The total capital cost of the transmission project must be greater than or equal to the lesser of $20 million or five percent of the constructing transmission owner's net transmission plant.[27]

- **Other Projects –** include the costs of network upgrades that are included in the MTEP, but do not qualify as Baseline Reliability Projects, new transmission access projects, Market Efficiency Projects, or MVPs.

Competitive Process Applicability

Baseline Reliability Projects are assigned to the applicable transmission owners when approved.[28] Market Efficiency Projects and MVPs are subject to MISO's competitive developer selection process unless such facilities: (1) are subject to a law granting a right of first refusal to the incumbent Transmission Owner, or (2) are an upgrade to existing facilities.

The competitive developer selection process does not apply to an eligible project that meets the MISOs' immediate-need reliability project criteria.[29] Immediate-need reliability projects are identified in a baseline reliability study and are needed within thirty-six months from approval; and designated as a Baseline Reliability Project.[30]

Stakeholder Engagement

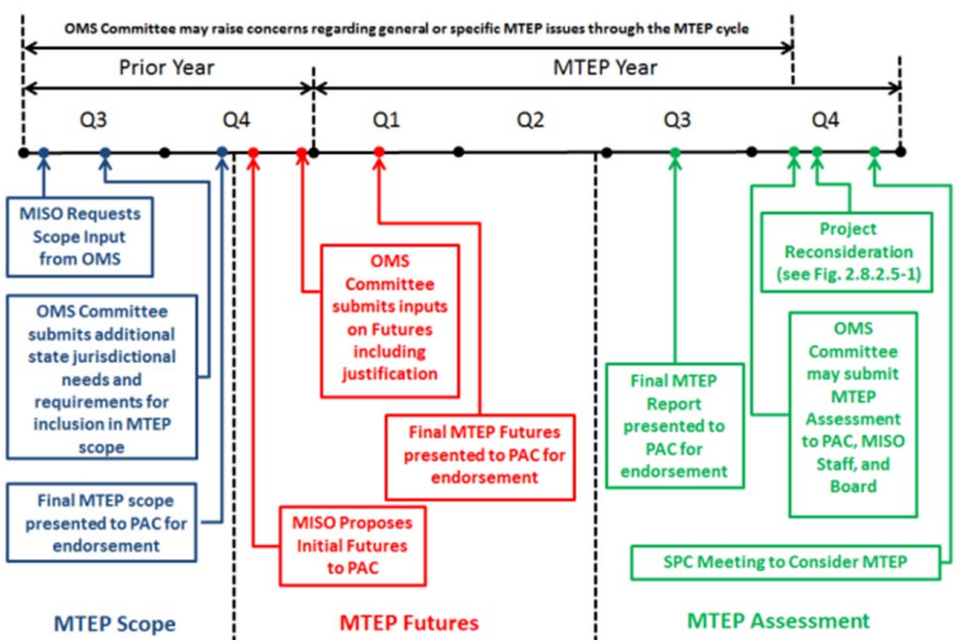
MISO planning staff engages with stakeholders through various planning groups and through working groups, task forces and workshops that may be organized by planning groups. The planning groups include the centralized Planning Subcommittee and the MISO PAC, as well as subregional planning groups, which providing an interface to stakeholders on a more localized basis.[31]

[26] MISO BPM 20, Section 7.4.
[27] MISO BPM 20, Section 7.5.
[28] Section II of Attachment FF of the MISO Tariff.
[29] MISO BPM 20, Section I.1.
[30] Section VIII.A.3 of Attachment FF of the MISO Tariff
[31] MISO BPM 20, Section 4.1.

As part of the transmission solutions process, stakeholders are given the opportunity to submit solutions to the identified issues. Solution ideas are used to inform the planning process. MISO, while working with stakeholders, may modify solution ideas throughout the MISO value-based planning process. MISO may also identify its own solution ideas to address transmission issues. MISO works with stakeholders to ensure solutions properly address the transmission issues.[32]

MISO, with input from stakeholders and considering all analysis performed to determine benefits and costs, will recommend projects to the MISO Board of Directors for approval. This recommendation is only provided for projects that have been shown to meet or exceed all criteria for type of project being recommended. After Board approval, MISO will determine if any of the qualified projects and facilities proceed to the developer selection process. Incumbent transmission owners have an obligation to put forth a good faith effort to construct facilities which do not go through developer selection.[33]

Figure 1: Stakeholder input through the MTEP cycle[34]:



32 MISO BPM 20, Section 4.4.2.4.
33 MISO BPM 20, Section 4.4.2.7.
34 BPM 20, Section 2.8.2.

Project Development Transparency

Reporting Requirements

The MTEP project database contains all transmission projects that are approved and/or recommended for approval but not yet in service, as well as all projects classified as bottom-up projects that are proposed and/or validated. The project database contains specific data for each individual project in the project database and each individual facility associated with each individual project in the project database. The project database includes all publicly available project status update data.[35]

In accordance with the MISO Tariff, transmission owners and developers are required to provide quarterly status updates to track the progress of all approved transmission projects.[36] MISO requests status updates on a quarterly basis via an e-mail sent to the MISO planning superlist (which contains the MISO PAC list), which are due no later than fifteen calendar days after the end of each quarter. MISO can also request additional status updates outside of the quarterly update cycle. If that happens, transmission owners and selected developers are required to provide MISO with the requested status update within ten (10) business days. These status updates are based on the best information known and available at the time, and are required to include the following information (applicable to "Eligible Projects," defined as MEP and MVP projects in the MISO OATT Module A):[37]

- Project schedule, including each facility's estimated in-service date and any material changes therein;
- Estimated project costs, including the estimated cost to complete each facility, any material changes therein as compared to the applicable baseline cost estimate, the total project expenditures to date, and the total project expenditures to date expressed as a percentage of the baseline cost estimate;
- Facility development status (e.g., under construction, in-service, completed, or withdrawn);
- Status of obtaining necessary regulatory and or environmental permits, certificates, or approvals, including meeting necessary licensing requirements;
- Status of land and right-of-way acquisition;
- Status of design and engineering;
- Status of any necessary interconnection agreements;
- An explanation of the causes of, or reasons for, any material changes to or deviations from the MTEP in-service date, baseline cost-estimate, and information provided in the last quarterly status report; and
- An assessment of the impact of any material changes on the project, including the continued ability to meet the MTEP in-service date.

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35 MISO BPM 20, Section 2.4.1.

36 Attachment FF §I.C.11 of the MISO Tariff.

37 MISO BPM 20, Section 4.2.3.1. *See Also* MISO OATT Module A for definition of Eligible Projects.

- A reporting template along with the appropriate contact and submittal information is posted on the planning page of the MISO web site.[38]

Project Cost Discipline

Variance Analysis

Under the MISO Tariff, MEPs and MVPs are subject to variance analysis by the RTO in the event of schedule delays, significant cost increases, or other factors. Unlike Baseline Reliability Projects, MEPs and MVPs are approved based on a benefit cost ratio (amongst other factors and criteria), which provides a basis for cost-based variance analysis.[39] Upon initiating a variance analysis, MISO seeks to further understand the reasons for a schedule or cost variance and to evaluate any potential impacts that they may have on the successful completion of the project or on the transmission system. This process is not unique to competitively bid projects. MEPs and MVPs that are assigned to the incumbent transmission owner or awarded through the competitive process are subject to variance analysis. [40] The requirement is in place until the projects are placed in-service.[41]

The variance analysis process is comprised additional analysis performed by MISO, in consultation with the transmission owner or developer, to understand the reasons for projected cost increases or schedule delays. MISO's Competitive Transmission Executive Committee has the exclusive and final authority to oversee and implement the variance analysis, including the decision to implement any of the appropriate variance analysis outcomes.[42]

There are four main grounds that could trigger a variance analysis. These four grounds are cost increases, schedule delays, inability to complete, or default under the Selected Developer Agreement.[43] If the transmission owner or selected developer determines that the estimated cost to complete project has either exceeded or is projected to exceed the baseline cost estimate by twenty-five percent or more, the project would be subject to a variance analysis.

In Phase 1, MISO performs an initial inquiry with the transmission owner or selected developer to confirm whether one or more identified grounds for commencing variance analysis exists. Phase 2 involves a process of data collection and analysis for the purpose of selecting the appropriate outcome for confirmed variance analysis grounds. The results of the variance analysis process

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38 MISO BPM 20, Section 7.7.

39 This includes any Market Efficiency Projects (MEP) and Interregional Economic Projects with voltage levels of 230 kV and above and Multi-Value Projects (MVP) approved by the Transmission Provider's Board after December 1, 2015, regardless of whether that project is subject to the Transmission Provider's Competitive Developer Selection Process.

41 MISO BPM 20, Section 8.1.

42 MISO BPM 20, Section 8.2.5.

43 MISO Tariff in Section IX.C of Attachment FF.

depend on the outcome selected and whether the project is a competitive transmission project or assigned to the incumbent transmission owner.

In Phase 2 of the variance analysis process, MISO considers the degree of fault of the project developer, the potential impacts to the transmission system and the MTEP, including potential reliability, economic, or public policy impacts; the degree of project completion; a comparison of the estimated costs of each outcome; a comparison of the degree to which each outcome are likely result in the successful completion of the project; and a comparison of the degree to which each outcome will alleviate the ground(s) for variance analysis.

MISO may elect to provide limited public notice that variance analysis has commenced once it has confirmed that one or more grounds exist. MISO will further evaluate the circumstances, events, and relevant facts associated with the variance analysis scope.

MISO collects information through Request for Information requests sent to the selected developer(s) or transmission owner(s) or third parties, followed by analysis, a cycle which may be repeated as many times as necessary before advancing to Phase 3.[44] Phase 3 consists of implementing the outcome that was selected in Phase 2.[45]

Re-evaluation Procedures

In Phase 3 of the variance analysis process, MISO will inform the applicable selected developer(s), transmission owner(s), and any other affected parties of the selected variance analysis outcome. Public notice is posted on the MISO website and includes the reason(s) the respective variance analysis outcome was selected. Outcomes include no action, a mitigation plan, a project reassignment of the applicable transmission owner or developer, or a cancellation of the project altogether.[46] The baseline cost estimate can be adjusted as part of the variance analysis.[47]

MISO will implement the approved variance analysis outcome in coordination with the applicable incumbent transmission owner(s), selected developer(s), and any other affected parties. If the approved variance analysis outcome includes a mitigation plan that alters the schedule, cost, design, or scope of a competitive transmission facility under a Selected Developer Agreement, MISO and the selected developer(s) amend the Selected Developer Agreement in accordance with the MISO Tariff. If the approved variance analysis outcome includes a reassignment or the cancellation of a

44 MISO BPM 20, Section 8.2.7.
45 MISO BPM 20, Section 8.2.6.
46 MISO OATT Attachment FF, Section IX.E.
47 MISO OATT Attachment FF, Section IX.C.1.1.

competitive transmission facility, MISO will file a notice of termination with the FERC.[48] The MISO Tariff also includes provisions for the resolution of variance analysis disputes.[49]

These reevaluation procedures promote transparency and cost discipline, and apply to projects both subject to and exempt from the competitive process.

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48 MISO BPM 20, Section 8.2.8.

49 Section IX.G of Attachment FF of the MISO Tariff and MISO BPM 20, Section 8.4.

SECTION 4:

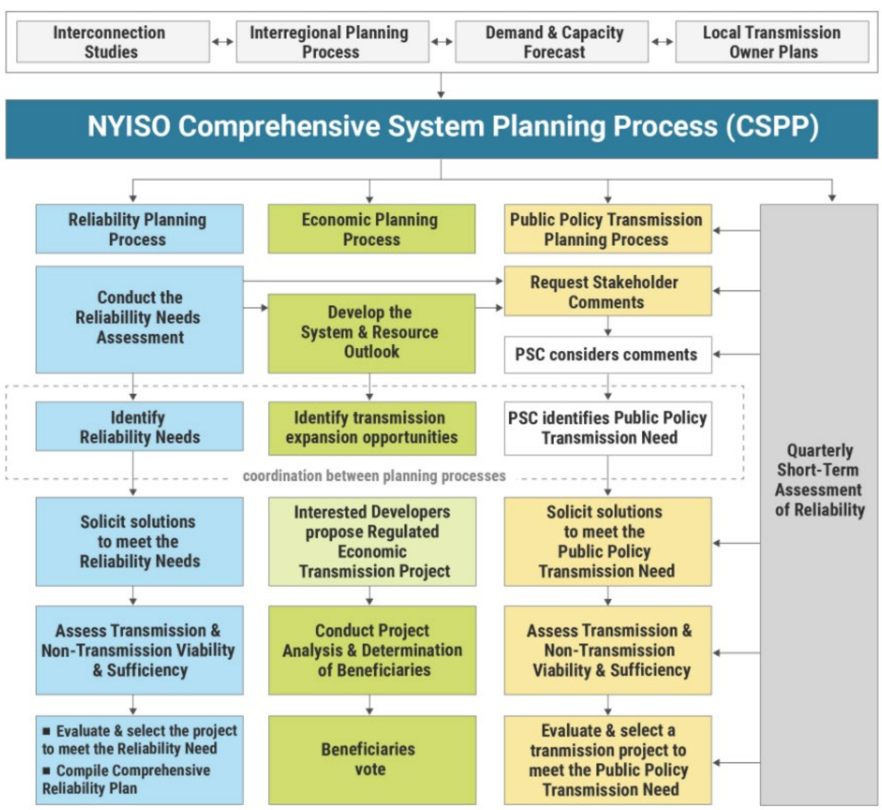
NEW YORK ISO

Transmission Planning Overview

Planning Procedures

The New York Independent System Operator (NYISO) is a single state ISO, which coordinates heavily with its state electric utility regulator, the New York Public Service Commission (NYPSC), on transmission planning matters. The NYISO manages and integrates a Comprehensive System Planning Process (CSPP), which begins with a Local Transmission Owner Planning Process (LTPP). The NYISO also manages a regional reliability transmission planning process, an economic transmission planning process ("market efficiency" projects), and a public policy transmission planning process.[50]

Figure 2: NYISO Comprehensive System Planning Process (CSPP)



50 https://www.nyiso.com/csppf

Project Development Transparency

NYISO maintains multiple planning processes, all of which rely on stakeholder involvement for optimum results.

Local Transmission Owner Planning Process

The NYISO's CSPP begins with the Local Transmission Owner Planning Process (LTPP). The LTPP allows interested parties to examine the transmission system plans of each of the New York transmission owners individually. Under the LTPP, each New York transmission owner posts on its website the planning criteria and assumptions currently used in its LTPP. Stakeholders can review and comment on the planning criteria and assumptions used by each transmission owner, as well as other data and models used in each LTPP.

During each two-year CSPP cycle, the NYISO holds one or more stakeholder meetings of the Electric System Planning Working Group and the Transmission Planning Advisory Subcommittee at which each transmission owner's current local transmission plan is discussed.

Regional Reliability Transmission Planning Process

The regional reliability transmission planning process produces reliability planning studies. These studies are used to identify and address the reliability needs of the system. The reliability planning process is discussed in the NYISO OATT Attachment Y, and its objectives are to evaluate the reliability needs pursuant to reliability criteria, provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; and provide a process by which the NYISO will select the more efficient or cost-effective regulated transmission solution.[51]

Economic Transmission Planning Process

The economic transmission planning process produces economic planning studies. These studies and evaluations are of the current and future state of congestion on the bulk power grid and the economic impact of projects to reduce that congestion. Their purpose is to summarize the current assessments, evaluations, and plans in the CSPP; project congestion on system and then identify, rank, and group the congested elements based on certain metrics.[52] This planning process also assesses the potential benefits of addressing the identified congestion.

Public Policy Transmission Planning Process

Pursuant to this process, the NYISO is responsible for selecting the more efficient or cost-effective transmission solution from among competing projects to address a transmission need driven by a

[51] NYISO OATT, Attachment Y.
[52] As set forth in in Sections 31.3.1.3.4 and 31.3.1.3.5 of OATT Attachment Y.

public policy requirement as identified by the NYPSC. This part of the transmission planning process in New York was established in accordance with FERC Order 1000 as a means to address public policy-driven transmission. This process allows stakeholders to propose transmission needs and solutions that are public policy driven; and provide a process whereby efficient or cost-effective solutions can be identified. This process also provides a cost allocation methodology for selected projects, and allows the ISO to coordinate with neighboring control areas.[53]

Project Development Transparency

Re-evaluation Procedures

In its April 2019 approval of transmission public policy projects, the NYISO outlined measures it took to evaluate, and re-evaluate public policy projects selected through the competitive process.[54] The Tariff directs NYISO staff to submit its selection report to the NYISO board for approval, via section 31.4.11.2 of the OATT. The NYISO Board of Directors relied on the NYISO agreement to review the matter on its own motion and set up a process by which developers were able to make presentations directly to the board before final decision.

The Board directed NYISO staff to conduct certain additional studies and analyses in its project selection, and then concluded that based on those additional studies and analyses, the more efficient or cost-effective transmission solution for Segment B was National Grid/Transco's Project T019, rather than NAT/NYPA's Project T029. This determination was made through a broad range of metrics. These re-evaluation measures provide an example of NYISO's ability to ensure the identified solution is the most efficient and effective for customers.

Project Cost Discipline

Cost Evaluations & Variance Analysis

Cost Cap Provisions

The NYISO also maintains provisions for procedures that provide for the consideration of cost containment in proposed public policy transmission projects. In addition, NYISO maintains a cost overrun rule for NYISO planned projects. Developers can voluntarily include these cost containment measures as part of their proposed transmission projects in the Public Policy Process. NYISO can assess these cost containment mechanisms when evaluating proposed transmission solutions and selecting the more efficient or cost-effective transmission solution to address a Public Policy

53 NYISO OATT, Attachment Y.

54 NYISO Board of Directors' Decision on Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects, April 8, 2019.

Transmission need.[55] The transmission owner or developer of a public policy project can submit a cost cap for its project in the form of a hard cost cap or a soft cost cap. A hard cost cap for is a dollar amount for those costs above which the transmission owner or developer commits not to recover from ratepayers. A soft cost cap is a dollar amount for above which the costs are shared between the transmission owner or developer and ratepayers based on a defined percentage. The transmission owner percentage of cost sharing under a soft cost cap is at least twenty percent.[56]

This provision dictates cost overrun and underrun recoverability for public policy projects and means that transmission owners or developers can recover only up to 20% of an overrun.[57] This rule is another example of simplified cost control measures that does not require expensive vetting, but whose outcome remains protective of customers.

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55 As proposed by NYISO in Docket ER20-617-000, December 17, 2019, and approved by the FERC in February 2020.

56 NYISO OATT Attachment Y, Section 31.4.5.1.8.3.

57 NYISO OATT Attachment Y, Section 31.

SECTION 5:

PJM INTERCONNECTION LLC

Transmission Planning Overview

Planning Procedures

PJM has the responsibility for planning the expansion and enhancement of the PJM transmission system on a regional basis. PJM's 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.

PJM and its members prepare a Regional Transmission Expansion Plan (RTEP) developed annually pursuant to Schedule 6 of the Amended and Restated Operating Agreement. The PJM RTEP process consists of the annual development and analysis of a baseline model that examines system topography at the time, which topography includes the current state of generation additions (by looking at the stage of projects in the interconnection queue) and retirements, the anticipated load forecast, cross-border transactions, and merchant transmission withdrawals. Based on that baseline, PJM then determines whether and to what extent regional transmission is needed to address conditions and issues on the system. Supplemental projects and projects the need for which are identified by Transmission Owners applying their respective FERC Form No. 715 criteria are included in the Local Plan and may be integrated into the RTEP base case. [58]

PJM currently applies planning and reliability criteria over a 15-year horizon to identify transmission constraints and other reliability concerns. The RTEP process, and the subsequent stakeholder review of transmission projects emanating from that process, determines the need for and benefits of a transmission project; it does not review or approve locations where transmission lines are ultimately built.[59] That is the responsibility of individual transmission owners who better understand the topography of their own respective service territories and then of individual states and municipalities who subsequently grant requisite zoning and land use approvals.

PJM's rules establish that, for regional reliability-driven projects that do not qualify for exemptions from competition (e.g. immediate need or below 200 kV) and that involve non-incidental expansions and enhancements to the existing regional grid as opposed to asset management, PJM utilizes a competitive planning process to determine the best fix for identified needs, including new transmission lines and upgrades.

58 PJM Manual 14B, Section 1.1.

59 PJM Manual 14B, Section 2.3.17

PJM Manual 14-B, "PJM Region Transmission Planning Process", describes PJM's planning process cycle – including interconnection planning – culminating in a single RTEP.

Stakeholder Engagement

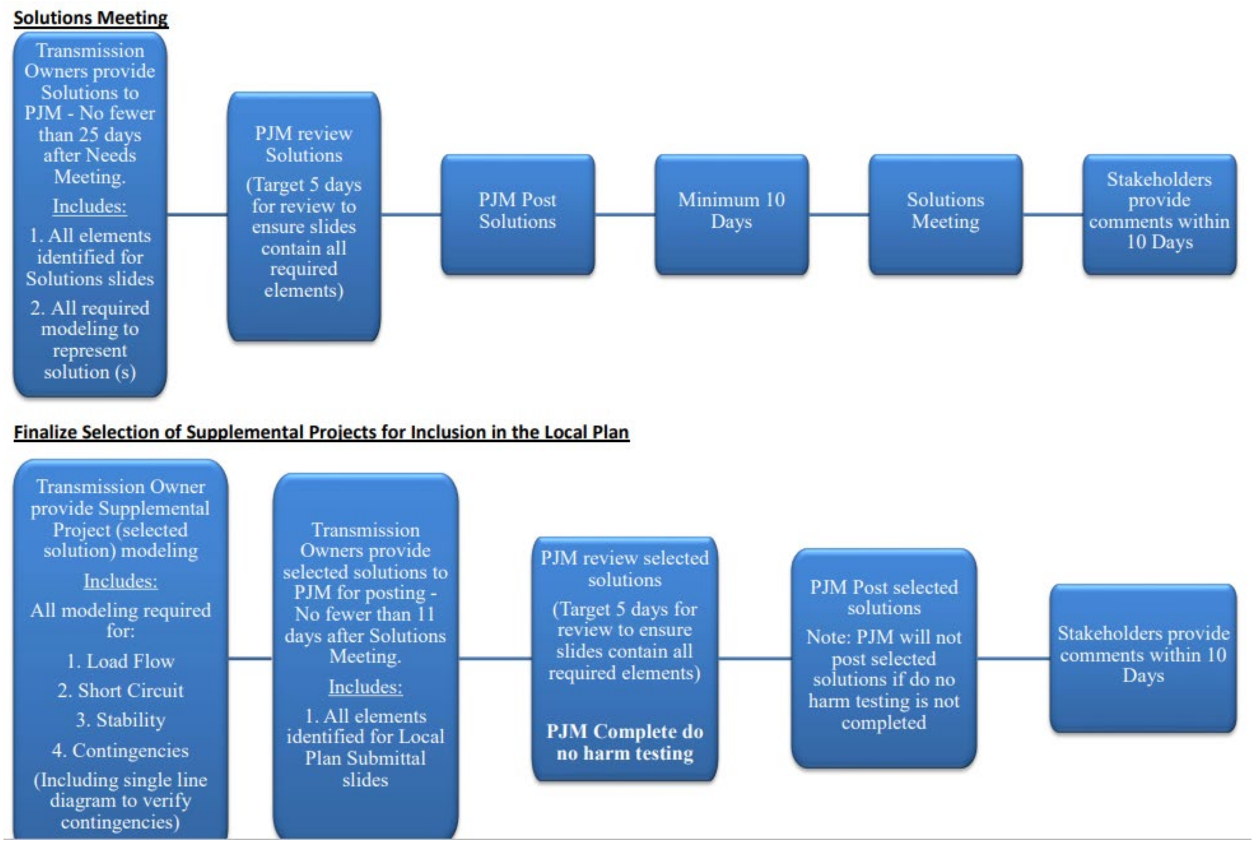
The RTEP reliability planning is open to stakeholder participation through the PJM Planning Committee, the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committees, and provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses with respect to both local and regional reliability. There are at least two Subregional RTEP Committee reliability reviews during the RTEP review for projects being evaluated at the Subregional RTEP Committee and multiple TEAC reviews for higher voltage projects that are evaluated at TEAC.[60]

As noted in the section above, with respect to regional reliability concerns that do not fall within a competitive solicitation exemption, PJM identifies potential problems and works with transmission owners and other PJM members through a competitive planning process to determine the best fix for the problem, meeting required technical standards. With respect to market efficiency, any PJM member may formally submit proposals for evaluation under the Market Efficiency analysis within the RTEP proposal window. These proposals are posted on the PJM website. Market efficiency proposals will not be accepted for acceleration or modifications to existing approved RTEP projects.[61]

For local reliability concerns, stakeholders can also use the FERC-approved Attachment M-3 Process to identify needs on a transmission owner's system that may be satisfied by a supplemental project and/or potential solutions to the needs identified by a Transmission Owner or stakeholder. Stakeholders may also provide comments or questions during each stage of the M-3 Process.[62] As highlighted in Figure 3 below, no fewer than 25 days after the needs meeting, each TEAC and Subregional RTEP Committee is required to schedule and facilitate a minimum of one meeting per planning cycle to review potential needs solutions. Transmission Owners and stakeholders are required to send solutions meeting slides and, for proposed solution, modeling information to PJM via email 15 days before a solutions meeting. Transmission Owners and stakeholders have a period of time to review and consider stakeholder comments and may revise its proposed solution. PJM provides standard slide elements for the submission of solutions proposals.[63]

60 PJM Manual 14B, Section 2.3.17.
61 PJM Manual 14B, Section 2.6.7.
62 Attachment M-3 Process Guidelines, Section 3.1.
63 Attachment M-3 Process Guidelines, Appendix 1.

Figure 3: PJM Workflow Approval



Project Cost Reporting

PJM Manual 14C describes the process of reporting and tracking projects driven by reliability criteria, enhanced market efficiency or Public Policy requirements. Project Milestones are defined in each designated entity agreement (DEA) and provide critical project measuring points and help communicate to team members the timeframe and scope of high-level project goals. The standard project milestones include the following, and may be customized as agreed to by the parties:

- Execute Interconnection Coordination Agreement;
- Demonstrate adequate project financing;
- Acquisition of all necessary federal, state, county, and local site permits;
- Substantial site work completed;
- Demonstrate required electrical ratings; and
- Required project in-service date[64]

[64] PJM Manual 14C, Section 6.1.1.1.

For baseline reliability projects assigned to transmission owners, construction responsibility letters (CRLs) are sent by PJM and executed by the transmission owner to codify the obligation to construct. Once upgrades have been identified and approved, PJM is responsible for tracking the status and completion of projects with the assistance of the transmission owners and designated entities. PJM may request additional information regarding projects consistent with PJM Manual 14B, section 1.4.2.3. Any permit or certificate delays that are anticipated to impact the projected in-service date should be timely communicated to PJM. Regular updates need to include the following:

- General status of engineering and construction (including any relevant regulatory siting authority approval necessary for the project and the status of such approval)
- Percent complete
- Current target in-service date or actual completion date
- Applicable outage information, in the form of outage ticket numbers
- Cost update[65]

Project updates including engineering progress, cost estimates, and constructions updates are reported as part of the regular status updates. The transmission owners(s) also provide updates to PJM, as needed, on specified project status updates and milestones, or acknowledgement that the current estimate is accurate.[66]

Project Cost Discipline

Cost Evaluations

PJM has a Transmission Cost Information Center (TCIC), an Excel-based application developed to help stakeholders understand current transmission costs and estimate future ones. TCIC includes information pre-populated for each PJM RTEP baseline and supplemental upgrade.[67] Users can update the default prepopulated input data in the TCIC with more appropriate information, as outlined in the TCIC User Guide.[68] Users can adjust values for projected revenue requirement items, such as the estimated construction-work-in-progress and true-up.

PJM publishes a summary table of select TCIC information, including status, and cost and milestone information for baseline, network and supplemental projects in PJM's RTEP.[69] PJM also publishes information for immediate-need projects, including the rationale for the immediate need, the review of the project(s) in the RTEP, and associated FERC filings.[70]

65 PJM Manual 14C, Section 6.1.2.
66 PJM Manual 14C, Section 6.1.2.1 Cost Tracking.
67 Whitepaper on (pjm.com)
68 Whitepaper on (pjm.com), p. 2.
69 PJM - Project Status & Cost Allocation
70 https://www.pjm.com/planning/project-construction/immediate-need-projects

Cost Thresholds

To ensure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of projects that have not commenced construction or have not received state siting approval are reviewed on an annual basis. Substantive changes in the costs and/or benefits of these projects are reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP. For projects with a total cost exceeding $50 million, an independent review of project costs and benefits is performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.[71]

Variance Analysis

Significant cost increases to baseline upgrades can change the analysis done to solve criteria violations and need to be communicated to PJM as they are discovered. PJM has the ability to use the updated cost data to re-analyze the criteria violation and determine if a different, more economical solution is better suited to solve the issue.[72]

Re-evaluation Procedures

Baseline reliability projects undertaken by transmission owners pursuant to CRLs sent by PJM are built and evaluated consistent with obligation to build provisions established by the Consolidated Transmission Owners Agreement (CTOA).

With respect to projects emanating from competitive solicitations, in addition to PJM Manual 14C provisions, the Designated Entity Agreement (DEA) executed by PJM and the developer awarded the competitive transmission project provides for revisions to the project scope and schedule through the project modification process. Because developers in this instance may not yet be bound by the CTOA, this process allows for changes to the scope, schedule or non-standard terms and conditions within the DEA to reflect the evolution of the project through the implementation phase. The project modification process may be initiated by the designated entity or PJM. The DEA is amended and refiled if the revisions captured by the scope change process are deemed material to the project.[73]

A party found in breach of a DEA is provided a notice describing in reasonable detail the nature of the breach and, if applicable, any steps that are necessary to cure the breach. The breaching party can clear the breach within 30 days or work in good faith beyond the 30-day period on all reasonable and appropriate steps to clear the breach. If the breach is not cured, PJM re-evaluates the project. That analysis can result in PJM retaining the project, removing the project, or including an alternative

71 PJM Manual 14B, Section 2.6.8.
72 PJM Manual 14C, Section 6.1.7.
73 PJM Manual 14C, Section 6.1.3.3.

project in the RTEP. If the project is retained in the RTEP, PJM determines if the project designation remains with the current designated entity or be changed to the incumbent Transmission Owner. Any RTEP change made relative to a project re-evaluation originating from a project breach is presented to the TEAC and approved by the PJM Board.[74]

[74] PJM Manual 14C, Section 6.1.3.4.

SECTION 6:

SOUTHWEST POWER POOL

Transmission Planning Overview

Planning Procedures

The Southwest Power Pool (SPP) has a responsibility to create regional transmission expansion plans through its Integrated Transmission Planning processes (ITPs). SPP creates planning models and studies through its stakeholder processes that determine what new transmission is needed to meet both short-term and long-term needs of the transmission network. The SPP OATT contains the rules that govern transmission planning.

The ITP is an annual planning cycle that assesses near- and long-term economic and reliability transmission needs. The 10-year ITP is assessed annually, and the 20-year ITC is assessed once every five years (unless otherwise directed by the SPP board of directors).

The process weighs long-term transmission investments against congestion costs for customers. ITP plans are reviewed by stakeholder groups and approved by SPP Board. The 20-year ITP is used to develop a recommended 345 kV and above "backbone" over a 20-year horizon. The 20-year ITP should enable transmission usage, generation access, and cost-effectiveness. The 20-year ITP relies on multiple planning and engineering models to develop and assess long-term transmission plans, and requires input from multiple stakeholder groups. [75]

Transmission Solution Evaluation

The SPP ITP is SPP's planning process for transmission upgrades needed to maintain reliability, provide economic benefits, and achieve public policy goals within the SPP region. Multiple stakeholder groups are involved in the process, which also involves extensive modeling exercises. These models derive the needs assessment for the determination of projects required in the region to meet reliability and public policy goals. Needs assessments are categorized as reliability, economic, public policy, and operational. SPP invites stakeholders to submit solutions to the system needs identified following the needs assessment. Solutions may include transmission solutions, model adjustments, operating guides, and non-transmission solutions.[76]

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75 https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/

76 See, e.g., SPP Integrated Transmission Planning Manual. Published on July 20, 2017, by SPP Staff. The ITP was approved by the SPP board of directors in April 2017 and approved by the Federal Energy Regulatory Commission (FERC) in December 2017. https://www.spp.org/documents/22887/itp%20manual%20version%202.0.pdf

As part of the solutions assessment, SPP maintains cost estimating procedures and practices described in its OATT Business Practices. The details of these assessments are discussed below.

Stakeholder Engagement

There is also a process in place for stakeholder engagement in the project approval process. A stakeholder who requests to have a project restudied must provide SPP with the necessary model changes needed to study the project modification within the appropriate models. If SPP determines that a change has occurred that could cause a project approval to be modified, SPP would perform the necessary analysis to determine if the project meets the required network upgrade justification. For a project modification to be considered reasonable, it must meet or exceed the original project justification.[77,78]

Project Development Transparency

SPP maintains explicit and detailed project planning procedures to establish reasonable baselines, expectations, and cost requirements, and reporting requirements for applicable projects.

Prior to the solution development phase in the ITP, SPP makes a preliminary determination of any proposed upgrades that are potentially competitive according to Attachment Y, Section I of the OATT for the limited purpose of determining the appropriate party to prepare the study estimate. Either SPP or a designated third party will prepare study estimates for potentially competitive upgrades. Incumbent transmission owner(s) will prepare study estimates for potentially noncompetitive upgrades. All study estimates will utilize the standardized cost estimate reporting template for all upgrades that are required to complete that project.[79]

Project reporting requirements are described in the SPP OATT Business Practices, Section 12. Designated transmission owners (DTOs) constructing an applicable project are required to provide updates to SPP on a quarterly basis. If the project cost exceeds certain cost bandwidths, a working group will monitor the project and take appropriate action if necessary.

Once a project is completed and placed in service, SPP has also set guidelines for a project close-out and validation process.[80] The requires each DTO to submit to SPP confirmation of commercial operation, pertinent modeling information for SPP's engineering purposes, actual costs, and relevant

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77 SPP OATT Business Practices, Section 6.3.

78 SPP's OATT Business Practices 7060, Notification to Construct and Project Cost Estimating Processes Effective January 1, 2012, govern SPP's rules around the evaluation of, and reporting on, new transmission projects.

79 SPP Integrated Transmission Planning Manual, p. 33.

80 SPP OATT Business Practices, Section 13.

GIS information. Once the information has been validated, the project becomes "closed out", and no longer tracked by SPP. The project close-out phase is also monitored for delinquency.

Application / Evaluation Procedures

An SPP Notification to Construct (NTC) letter is a formal document directing the DTO for the commencement of construction of Network Upgrades that have been approved or endorsed by SPP. A Notification to Construct with Conditions (NTC-C) letter directs the DTO to further refine the Study Estimate for an applicable project before it can commence construction.[81]

Reporting Requirements

At the outset of determining project approval, projects are assigned a series of identifying information. This ensures proper and consistent documentation of approved projects. This information includes project identification numbers, description of the project, estimate costs and schedules, project owner details, categorization (e.g., economic as a part of a balanced portfolio, integrated transmission planning process, sponsor upgrade, service upgrades, zonal reliability upgrade, etc.). The project information also includes unit specifications, network upgrade justification, need date, cost information, and cost recovery plan.[82]

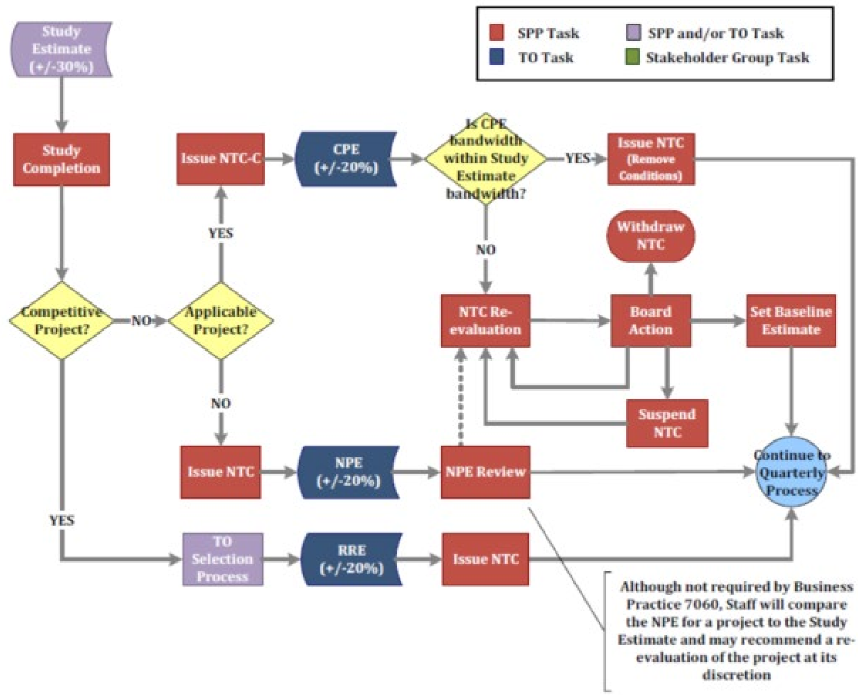
Project Cost Reporting

The project specification and cost estimation process are described and outlined in SPP's OATT Business Practices, Section 8. The project cost estimate begins with the conceptual estimation phase which is prepared by SPP based on historical cost information in the SPP database, and updated based on new information provided by the DTO.

[81] SPP OATT Business Practices, Section 3.

[82] SPP OATT Business Practices, Section 4.

Figure 4: SPP Cost Estimation Process[83]



Next, the study estimate phase refines the conceptual estimate after the project has passed through several screening criteria. This is the estimate against which SPP compares final project costs for its variance reporting.[84]

As noted above, certain project information is reported and tracked at the outset of project approval. The information that regarding project costs includes the cost estimate in present day dollars, and the date and origination of the cost estimate. The cost recovery method is also tracked (e.g., base plan allocated, direct assignment, project sponsor, zonal, regional, or other).[85]

Project Cost Protections

Cost Thresholds

A single project under review by SPP may consist of multiple upgrades or multiple projects assigned to multiple DTOs. SPP's Business Practices include a project approval threshold of nominal operating voltages of 100 kV or above if either its project estimate or any subsequent cost estimate exceeds $20

83 SPP OATT Business Practices, Appendix C.
84 SPP OATT Business Practices, Section 8.
85 SPP OATT Business Practices, Section 4.3.

million. Applicable projects will continue within this reporting process even if their subsequent cost estimates fall below $20 million. For projects which would otherwise be applicable, but did not receive an NTC from SPP as part of the new member integration process, the initial cost estimate received from the project owner and reported in quarterly project tracking is used as the established baseline cost estimate for reporting all future cost estimate changes during the project tracking process is the basis for determining project cost variances. SPP provides guidelines for both competitive and non-competitive projects.[86]

Figure 5: Cost Estimate Stage Definition Overview[87]

Estimate Name	Stage			End Usage	Precision Bandwidth
	Non-Competitive Projects		Competitive Projects		
	Projects > 100 kV & > $20 Million	All other Board Approved Projects			
Conceptual (SPP Prepared)	1	1	1	Concept screening for ITP Assessment	-50% to + 100%
Study	2	2	2	Study of feasibility and plan development for ITP Assessment	-30% to +30%
	NTC-C Issued	*NTC Issued*	*RFP Issued*		
NTC-C Project (CPE)	3	N/A	N/A	Established baseline (NTC-C)*	-20% to +20%
	New NTC Issued				
NTC Project (NPE)	N/A	3	N/A	Established baseline (NTC)*	-20% to +20%
RFP Response (RRE)	N/A	N/A	3	Established baseline (RFP Response)*	-20% to +20%
			NTC Issued		
Design & Construction (DCE)	4	4	4	Design after NTC issued to build the project	-20% to +20%**

**Board approval required to reset the baseline.*
***Final cost is expected to be within +/-20% of established baseline estimate.*

A project working group comes into play if a project exceeds these cost bandwidths, as described in the SPP OATT Business Practices, Sections 10 and 11.

Variance Analysis

As noted above, project approval either gets an NTC letter or an NTC-C letter, which requires further consideration. In terms of cost variance analysis, SPP maintains certain cost variance bandwidths against which a project estimate is deemed reasonable. If the cost variance bandwidth of -20% to +20% does not exceed the study estimate variance bandwidth of -30% to +30%, the project's cost variance is deemed acceptable and SPP will provide project authorization. In other words, if the CPE

86 SPP OATT Business Practices, Section 2.
87 SPP OATT Business Practice, Section 8.7.

is not greater than 1.0833 times the study estimate and is not less than 0.875 times the study estimate, an NTC will be issued with no further review.

However, if the variance bandwidth exceeds the variance bandwidth of -30% to +30% of the study estimate, SPP will re-evaluate the project using the new cost estimate data provided by the TO, and will make a recommendation to the Board at its next regularly scheduled meeting. In other words, if the CPE is greater than 1.0833 times the study estimate or is less than 0.875 times the study estimate SPP staff will re-evaluate the project. The CPE received from the DTO will be used as the established baseline cost estimate for reporting all future cost estimate changes during the project tracking process for the project and will be the basis for determining project cost variances.[88]

Re-evaluation Procedures

As is to be expected, certain changes to a project scope such as changes in load of generation, or a change in local planning criteria, might cause SPP to restudy the project and therefore would affect the project cost estimate.[89]

88 SPP OATT Business Practices, Section 5.1.

89 SPP OATT Business Practices, Section 5.1.