Manual No. 020

Business Practices Manual

Transmission Planning

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Revision History

Doc Number	Description	Revised by	Effective Date
BPM-020-r31	Annual review, 2024	T. Armstrong	AUG-1-2024
BPM-020-r30	Update section 4.2.3 to define "qualified change" for FAC-002-4 revision Update sections 4.3.1.2 and 4.3.1.2.2 on selection of non-transmission alternatives Section 6.3 regarding SSR threshold criteria	Z. Zhou J. Furnish S. Goodwin Grant Larson	DEC-1-2023
BPM-020-r29	Updates include the following items: Corrected TPL reference in Appendix K Corrected Table reference in Appendix K Verified all hyperlinks Placed borders around all figures w/ none Emphasized references to other documents Annual Review Complete	S. Goodwin	MAY-1-2023
BPM-020-r28	Updates include the following items: 1) New Appendix G – TPL-007 voltage criteria 2) New 4.3.7.1 Section for Spare Equipment Strategy contingency solicitation	S. Goodwin	DEC-31-2022
BPM-020-r27	Updates include the following items: 1) Updates to the alternative submission process Section 4.3.1.2 2) New Section 4.3.4.2.1, MISO Default Methodology for Selecting P5 Contingencies 3) New Appendix F, default methodology for P5 contingency selection 4) Fix Appendix L reference to Section 4.3.3.2 Annual Review Complete.	S. Goodwin	MAY-01-2022
BPM-020-r26	Updates include the following items: 1) New Appendix A, added requirements to select an electric storage facility as a Storage As Transmission-Only Asset (SATOA) 2) Updated section 4.2.3.1, for project status reporting process	S. Goodwin	MAR-01-2022
BPM-020-r25	Updates include the following items: 1) Updated Section 2.1, to align planning principles with MISO Board of Directors' review and approval 2) Updated Section 2.3.2.3, for INRP process 3) Updated Section 4.3.5.2, in response to FAC-013 retirement 4) New Section 4.3.6, to align with revised TPL-001-5 requirements for planned outages	S. Goodwin	NOV-01-2021

Doc Number	Description	Revised by	Effective Date
	5) New Section 4.3.7, to align with revised TPL-001-5 requirements for long lead time equipment outages 6) New Appendix E, added language so Sector members can access MISO Planning data. 7) New Appendix I, added for INRP process 8) Updated Appendix L, in response to FAC-013 retirement 9) Updated Appendix N, in response to FAC-013 retirement		
BPM-020-r24	Updates include the following items: 1) Hyperlinks refreshed 2) Client Relations contact info updated 3) Chapter 7 - MEP updates to comply with Tariff modifications filed in Docket No. ER20-1723 and ER20-1724 Annual Review Complete	S. Goodwin	MAY-01-2021
BPM-020-r23	Updates include the following items: 1) Section 4.5.3.2.1 - Updated FTR Market Administration group name 2) Section 7.4.2 – Enhance approach to estimating costs over time in the planning process 3) Updated all hyperlinks throughout Annual Review Complete	S. Goodwin	DEC-01-2020
BPM-020-r22	Updates include the following items: 1) Clean up Section headings to improve ToC Annual Review Complete	S. Goodwin	MAY-01-2020
BPM-020-r21	Updates include the following item: 1) Section 8 - Variance Analysis, revisions to further explain the Variance Analysis process and incorporate revisions filed in in Docket No. ER20-303-000 2) Revision history table change in the rev20 section, renumber and offer clarity 3) Updated Appendix M to better align the BPM-020 language w/ PRC-023-4	S. Goodwin	FEB-02-2020
BPM-020-r20	Updates include the following items: 1) Revision History Table change in the rev19 section, item No. 3 was clarified. 2) Updated Section 2.8.1, Guiding Principals 3) Appendix J, Cost Allocation	S. Goodwin	AUG-01-2019
BPM-020-r19	Updates include the following items: 1) Updated Section 2.1 on Guiding Principles 2) Updated Section 2.8.1 on MTEP Guiding Principles. 3) Revised project status reporting within Section 4.2 for clarity of milestone responsibility for Eligible Projects and report timing	S. Goodwin	APR-01-2019

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	4) Updated Section 3.3.3 5) Updated Section 4.3.1 for clarity on SSRs 6) Updated Section 4.3.3.2 for clarity on SSRs Annual Review Complete		
BPM-020-r18	Updates include the following items: 1) Updated Hyperlinks to point to new MISO public internet. 2) Aligned Section 4.2.3.1.1 with recent Tariff changes Annual Review Complete	S. Goodwin	MAY-01-2018
BPM-020-r17	Updates include the following items: 1) Appendix L – SOL (IROL) Methodology for the Planning Horizon a. Section L.3 – added language to address Reliability margins in planning horizon. b. Section L.3.6 – added language to explain rationale for 1000 MW criteria c. Section L.3.6 – added language to address T_v in planning horizon 2) Section 4.3.1 – revised language 3) Section 4.3.4.1 – added clarification around P6-1-1 definition 4) Section 4.5.1 – revised language, removing duplicative language in BPM-011 5) Section 5.5.2 – language removed, section reserved for future usage	S. Goodwin	OCT-01-2017
BPM-020-r16	Updates include the following items: 1) Section 4.4 - Long-term Planning 2) Section 6.2 - Generator Retirement and Suspension Studies and System Support Resources (SSR), wholesale replaced with updated language. 3) Other cosmetic formatting	S. Goodwin	DEC-01-2016
BPM-020-r15	Updates include the following items: 1) Section 4.2.3.1 and all subsequent subsections were wholesale replaced with new language 2) New Section 8 added, with all subsection additions	S. Goodwin	SEPT-01-2016
BPM-020-r14	Updates include the following items: 1) Added new TPL-001-4 language throughout 2) Added new Appendix O (rev13) 3) Cosmetic cleanup throughout 4) Refreshed some Figures and Tables 5) Standardized all captions throughout 6) Standardized all bullets throughout	M. Tackett / S. Goodwin	JUN-01-2016

Doc Number	Description	Revised by	Effective Date
	Annual Review Complete		
BPM-020-r13	Updates include the following items: 1) Delete Section 1.5 2) Rename Section 4 3) Rewrite Section 4 Introduction 4) Add Subsection 4.1.4 5) Rewrite Section 4.3 6) Renumber Subsection 4.3.4 to 6.1 7) Renumber Subsection 4.3.8.4 to 4.5.1 8) Renumber Subsection 4.3.8.5 to 4.5.2 9) Renumber Subsection 4.3.9 to 4.5.3 10) Add New Section 4.5 11) Renumber Section 4.5 to 4.6 12) Renumber Section 4.6 to 4.7 13) Rename Section 6 14) Delete Section 6.1 15) Rewrite Appendix K 16) Delete Appendix O Annual Review completed	M. Tackett/ S. Goodwin	MAY-10-2016
BPM-020-r12	Updates include the following items: 1) Minor editorial changes in the entire document 2) Section 2.3: Completely rewritten 3) Section 2.4: Completely rewritten 4) Section 6.2: Editorial changes 5) Appendix N: Corrected the reference to Appendix P. 6) Added Appendix P: Methodology for Assessment of Low Voltage Facility Impacts on BES Annual Review Completed	T. Adu	APR-28-2015
BPM-020-r11	Updates include the following items: 1) Section 4.3.8.4 – Revised section on Baseline 2) Load Deliverability	M. Sutton	NOV-30-2014
BPM-020-r10	Updates include the following items: 1) Section 2.4.1.1: Change to BRP Cost Allocation 2) Section 2.4.1.2 I): Change to ITCM GIP Cost Allocation 3) Section 2.8: OMS Committee Role in Transmission Planning section added 4) Section 4.2.3.1: Project Status updates section added	M. Dantzler	APR-10-2014

Doc Number	Description	Revised by	Effective Date
	5) Section 6.1: Out-of-Cycle Project Review section revised 6) Section 6.2.6: System Support Resource (SSR) Methodology section added 7) Section 7: Changes to BRP Cost Allocation and updated section references 8) Section 7.1: Moved LODF language to Appendix J and updated language with BRP changes Appendix J.5.1: Moved language to new Appendix O Annual Review Completed		
BPM-020-r9	Updates include the following items: 1) Section 4.3.4: Review of Market Participant Funded Projects section added 2) Appendix J, Section 5.1.1 thru 5.3: Revised language regarding upgrades based on outages during maintenance periods 3) Appendix L: Revised SOL identification methodology 4) Appendix M: Revised to update methodology for new standard PRC-023-2 5) Appendix N: Added new methodology for FAC-013-2: Transfer capability performed in the planning horizon Annual Review Completed	M. Dantzler	MAY-28-2013
BPM-020-r8	Updates include the following items: 1) Section 4.3.3 – Revised section on Short-term Planning Analysis	M. Dantzler	JAN-17-2013
BPM-020-r7	Updates include the following items: 1) Section 2.4.1.3 – New MEP cost allocation 2) Section 7 – GIP, MEP and MVP cost allocation updates; cost shared projects 3) Remove Section 6 – Generator Interconnection Planning – Duplicate section in BPM-015, owned by the Generator Interconnection Planning Department Annual Review Completed	M. Dantzler	NOV-19-2012
BPM-020-r6	Updates include the following items: 1) Additional language in Appendix L to clarify communication 2) Add Appendix M: Critical Facility Methodology	A. Dortch	NOV-15-2011
BPM-020-r5	1) Section 5: Long Term Transmission Services	P. Muncy/ M. Sutton	SEP-22-2011
BPM-020-r4	Updates include the following items: 1) Multi-Value Project Cost Allocation criteria and methodology	M. Tackett	MAR-09-2011

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	2) Shared Network Upgrade methodology Regionally Beneficial Project name change to Market Efficiency Project. Reflects Tariff revisions with an effective date of July 16, 2010.		
BPM-020-r3	1) Appendix J: Additional Language on system reconfiguration and redispatch evaluation for Category C3 events for LODF Calculation 2) Section 2.6.1: Expand on MISO Transmission Provider responsibilities 3) 3) Appendix L: Additional Language on SOL/IROL Methodology	A. Dortch	NOV-20-2010
BPM-20-r2	1) Update to incorporate changes to transmission planning process 2) Update Generator Interconnection section	M. Tackett	OCT-20-2010
BPM-020-r1	Annual Review Completed	A. Dortch	JUL-08-2009
TP-BPM-002-r1	1) Section 4.3.6: Language Changes in MTEP Contingency Selection Process 2) Section 4.3.7.1: Language Changes in MTEP IROL Identification Process 3) Section 4.3.7.8: New Language describing process for planning for feasibility of LTTR's 4) Appendix J: Additional Language on 5) Implementation Rules for LODF Calculation	J. Webb	JUL-08-2009
TP-BPM-002	Original Posting	S. Goodwin	12-07-2007

Table of Contents

1 Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM) for Transmission Planning* includes basic information about this BPM and the other MISO BPMs. The first section (*Section 1.1*) of this Introduction identifies the other BPMs that are available. The second section (*Section 1.2*) is an introduction to this BPM. The third section (*Section 1.3*) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of MISO Business Practices Manuals

The BPMs developed by MISO provide background 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. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

1.2 Purpose of this Business Practices Manual

This *BPM for Transmission Planning* describes MISO's transmission planning process. Also included in this BPM is the former *BPM-013 – Transmission Services.*

1.3 References

Other reference information related to this BPM includes:

- Tariff (Tariff)
- Agreement of the Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (MISO Agreement)
- BPM-004 Financial Transmission Rights and Auction Revenue Rights
- BPM-005 Market Settlements
- BPM-011 Resource Adequacy
- BPM-015 Generation Interconnection
- BPM-027 Competitive Transmission Process
- NERC Reliability Standards applicable to transmission planning

1.4 MISO Planning Contacts

For information on MISO planning staff contact details for specific planning functions, contact Client Relations: Client Relations.

2 Overview of Transmission Planning

2.1 MISO Transmission Planning Objectives

The MISO Transmission Expansion Plan, created in conjunction with an inclusive, transparent stakeholder process, must identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs, enable a competitive energy market, support policy goals, and allow for competition among transmission developers in the assignment of transmission projects. Upon the recommendation of the Board's System Planning Committee, the Board of Directors provides the following Guiding Principles to the MISO staff as it fulfills its RTO system expansion planning obligations.

- In support of these goals, the MISO regional expansion planning process should: Develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the MISO region.
- Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.
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- Support federal, state, and local energy policy and member goals by planning for access to a changing resource mix.
- Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- Analyze system scenarios and make the results available to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.
- Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

Also, it is MISO's goal for the planning process to be fully compliant with the Planning Principles presented in the Federal Energy Regulatory Commission's (FERC) Order Nos. 890 and 890-A. In Order No. 890, FERC identified nine planning principles "that must be satisfied for a transmission provider's planning process to be considered compliant with the Final Rule". MISO has incorporated each of the following principles *shown in Section 2.1.1* below into its planning process and describes their functions in this Manual.

2.1.1 FERC Order No. 890 Planning Principles

- Coordination
- Openness
- Transparency
- Information Exchange
- Comparability
- Dispute Resolution
- Regional Participation
- Economic Planning Studies
- Cost Allocation for New Projects

2.2 Transmission Planning Functions and Cycles

2.2.1 Planning Functions

The development of the overall MISO Transmission Plan encompasses multiple planning functions addressing different phases and aspects of transmission planning. These functions include:

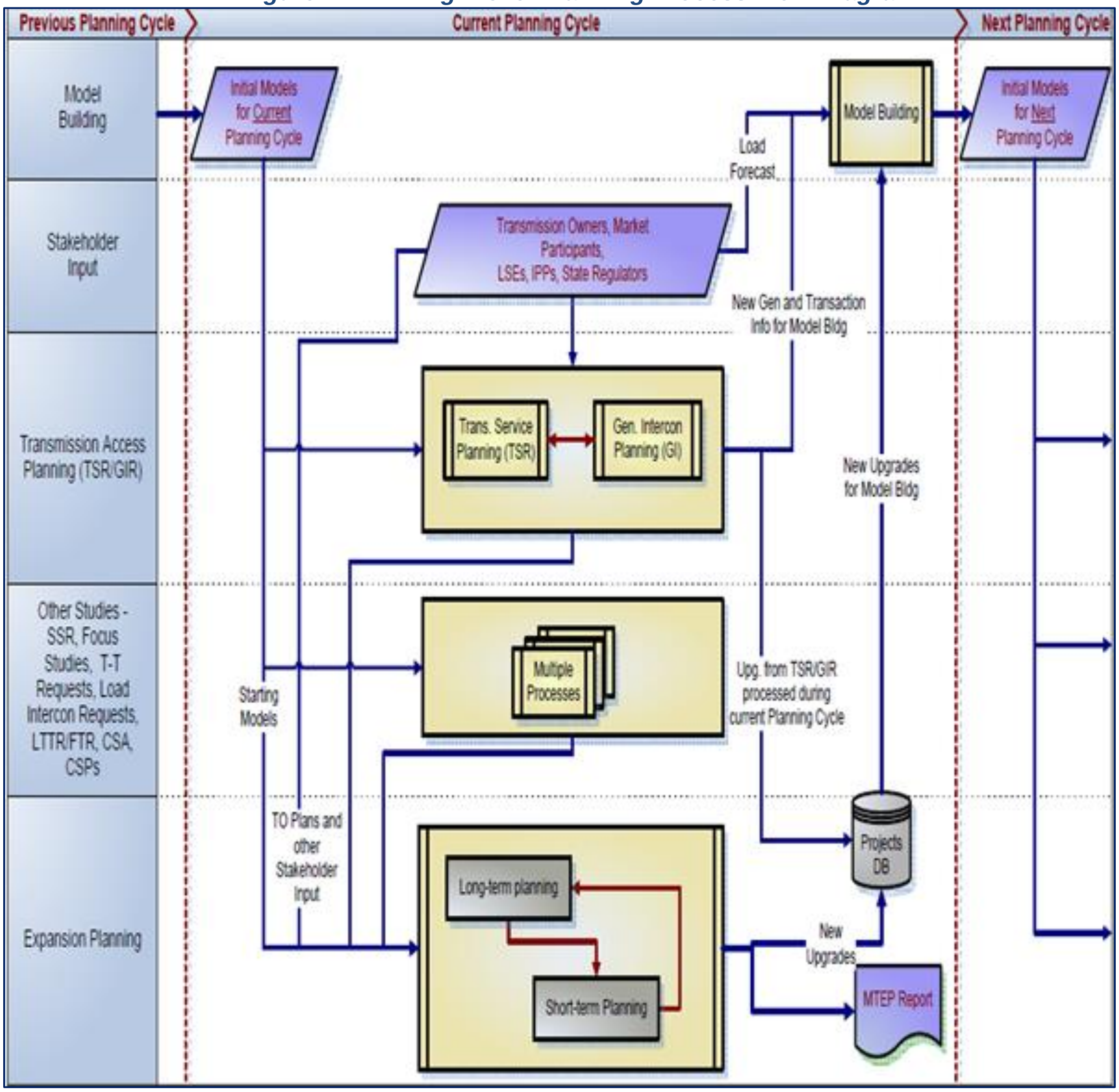
- Model Development
- Cyclical bottom-up and top-down Planning
- Transmission Access Planning
  - Generator Interconnection Planning
  - Transmission Service Planning
- Coordinated Inter-regional Planning (with other RTOs/Regions)
- Non-cyclical Planning Needs
- System Support Resource (SSR) Studies for unit de-commissioning
- Transmission Interconnections
- Load Interconnections
- Focus Studies - Studies initiated during the cyclical planning process that cannot wait until the next planning cycle (e.g., NERC/FERC directives, near-term critical operational issues)

Each of these functions are described in this BPM.

2.2.2 Integration of Planning Functions to Produce MTEP

The various planning functions occur at differing times. For example, the transmission access planning processes occur on a continuous basis in response to customer requests for service. The bottom-up and top-down planning functions repeat on a regular cycle, with an MTEP report produced every twelve (12) Months. Each of these processes informs the other at the commencement of each functions cycle, *as shown in Figure 2.2.2-1 below*.

Figure 2.2.2-1: High-level Planning Process Flow Diagram



2.3 Transmission Project Categories and Types

This section describes the categories and types of transmission projects associated with the MISO transmission planning process. There are three distinct categories of transmission projects which include the following:

- Bottom-Up Projects
- Top-Down Projects

- Externally Driven Projects

The specific types of transmission projects include the following:

- Other Projects
- Baseline Reliability Projects
- Market Efficiency Projects
- Multi-Value Projects
- Generation Interconnection Projects
- Transmission Delivery Service Projects
- Market Participant Funded Projects

Table 2.3-1 below illustrates how specific transmission project types map to their parent transmission project categories:

Table 2.3-1: Transmission Project Type-to-Category Mapping

	Bottom-Up Projects	Top-Down Projects	Externally Driven Projects
Other Projects	X		
Baseline Reliability Projects	X		
Market Efficiency Projects		X	
Multi-Value Projects		X	
Generation Interconnection Projects			X
Transmission Delivery Service Projects			X
Market Participant Funded Projects			X

A 'Storage As Transmission-Only Asset' (SATOA) may qualify as any transmission project type as defined under the Tariff. The requirements to select an electric storage facility as a SATOA are further described in *Appendix A of this BPM*.

2.3.1 Transmission Project Categories

This section describes the three transmission project categories.

2.3.1.1 Bottom-Up Projects

Bottom-up projects include transmission projects classified as other projects and Baseline Reliability Projects. Bottom-up projects that are ultimately classified as other projects or Baseline Reliability Projects are not cost shared and are generally developed by Transmission Owner(s), via their role as the NERC Transmission Planner (TP), to address localized Transmission Issues and reliability-related Transmission Issues including, but not limited to, compliance with the NERC reliability standards. In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues. In some situations, MISO, as the Planning Coordinator, may also recommend certain bottom-up projects if MISO analysis determines that additional expansion is necessary to comply with the NERC or regional reliability standards. Furthermore, MISO may also recommend alternative solutions to bottom-up projects submitted by Transmission Owner(s), and the expansion planning process will consider those alternative solutions along with the submitted bottom-up projects. Bottom-up projects are produced by the process described in more detail *in Section 4.3 of this BPM*. Bottom-up projects have a right-of-first-refusal and are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement when approved.

2.3.1.2 Top-Down Projects

Top-down projects include transmission projects classified as Market Efficiency Projects and Multi-Value Projects. Top-down projects include subregional and regional projects developed solely by the MISO planning process in accordance with Attachment FF and with this BPM as well as interregional projects developed jointly with one or more other planning regions in accordance with applicable Joint Operating Agreements or Tariff provisions as appropriate. Regional or subregional top-down projects are developed in a top-down manner by MISO staff working in conjunction with stakeholders to address regional economic and/or public policy Transmission Issues. Regional or subregional top-down projects that are ultimately classified as Market Efficiency Projects or Multi-Value Projects are cost shared per provisions in the Tariff. Interregional top-down projects are developed in a top-down manner by MISO and one or more other planning regions in conjunction with stakeholders to address interregional Transmission Issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or Tariff, first between MISO and the other planning regions, then within MISO based on provisions in Section III of Attachment FF of the Tariff. Top-down projects are produced by the process described in more detail *in Section 4.4 of this BPM*. Certain facilities associated with top-down projects may or may not have a right-of-first-refusal and thus will either be assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement and/or awarded via the provisions of *Section VIII of Attachment FF of the Tariff and with BPM-027 – Competitive Transmission Process*.

2.3.1.3 Externally Driven Projects

Externally driven projects are projects driven by needs identified outside of the MISO Transmission Expansion Plan (MTEP) planning process. Externally driven projects typically include New Transmission Access Projects, which are defined in *Module A of the Tariff*, as well as other Network Upgrades that are driven by and benefit a single specific Transmission Customer or Market Participant. Externally driven projects include Generation Interconnection Projects, which are New Transmission Access Projects developed in accordance with *Attachment X of the Tariff*; Transmission Delivery Service Projects, which are New Transmission Access Projects developed in accordance with Module B of the Tariff; and Market Participant Funded Projects, which are developed pursuant to *Section 6.1 of this BPM*. Externally driven projects are generally not cost shared although there are exceptions (e.g., certain Generator Interconnection Projects may be cost shared). Externally driven projects have a Right Of First Refusal (ROFR) and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2 Transmission Project Types

This section describes the eight transmission project types.

2.3.2.1 Other Projects

Other projects represent local transmission projects that address localized Transmission Issues other than the reliability issues addressed by Baseline Reliability Projects, and thus other projects are not projects used to address projected violations of NERC and regional reliability standards. Other projects may include projects to satisfy Transmission Owner and/or state and local planning criteria other than NERC or regional reliability standards, interconnect new Loads, relocate transmission facilities, address aging transmission infrastructure, replace problematic transmission plant, improve operational performance or address other operational issues, address service reliability issues with end-use consumers, improve aesthetics including but not limited to undergrounding overhead transmission facilities, address localized economic issues, and address other miscellaneous localized needs. Other projects are not cost shared through the Tariff and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2.2 Baseline Reliability Projects

Baseline Reliability Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff* and represent transmission projects needed to comply with Electric

Reliability Organization (i.e., NERC) reliability standards and regional reliability standards. Baseline Reliability Projects are not cost shared through the Tariff and are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* when approved.

2.3.2.3 Market Efficiency Projects

Market Efficiency Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff. They* represent transmission projects that address Transmission Issues related to market transmission congestion. Market Efficiency Projects are cost shared in accordance with *Section III of Attachment FF of the Tariff*.

Facilities comprising Market Efficiency Projects approved by MISO's Board after December 1, 2015 are subject to MISO's Competitive Developer Section Process unless such facilities: (1) are subject to a law granting a right of first refusal to the incumbent Transmission Owner[1]; (2) qualify as upgrades to existing transmission facilities[2]; or (3) qualify as an Immediate Need Reliability Project as described *under Appendix I of this BPM*.[3] Market Efficiency Projects that are subject to the Competitive Developer Selection Process are awarded in accordance with the procedures specified *in Sections VIII.C through VIII.I of Attachment FF and in Business Practices Manual 027 (Competitive Transmission Process)*. Facilities that are exempt from the Competitive Transmission Process are

assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* or applicable law. A Market Efficiency Project may consist of some facilities that are subject to the Competitive Developer Selection Process and others that are not.

2.3.2.4 Multi-Value Projects

Multi-Value Projects are defined in *Module A of the Tariff* and described in *Section II of Attachment FF of the Tariff* and represent portfolios of transmission projects that address multiple types of Transmission Issues (e.g., public policy, economic, reliability, etc.) on a region-wide basis. Multi-Value Projects are cost shared projects in accordance with *Section III of Attachment FF of the Tariff*.

Facilities comprising Multi-Value Projects approved by MISO's Board after December 1, 2015 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[4]; or (2) qualify as upgrades to existing transmission facilities.[5] Multi-Value Projects that are subject to the Competitive Developer Selection Process are awarded in accordance with the procedures specified *in Sections VIII.C through VIII.I of Attachment FF and in Business Practices Manual 027 (Competitive Transmission Process)*. Facilities that are exempt from the Competitive Transmission Process are

[1] Tariff Attachment FF at Section VIII.A.1.
[2] Tariff Attachment FF at Section VIII.A.2.
[3] Tariff Attachment FF at Section VIII.A.3.
[4] Tariff Attachment FF at Section VIII.A.1.
[5] Tariff Attachment FF at Section VIII.A.2.

assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* or incorporated into an Competitive Transmission Project and awarded in accordance with *Section VIII of Attachment FF of the Tariff* when approved.

2.3.2.5 Generator Interconnection Projects

Generator Interconnection Projects are New Transmission Access Projects that are defined in *Module A of the Tariff* and described in *Attachment X of the Tariff*. Generation Interconnection Projects represent transmission projects required to facilitate the interconnection of a new Generation Resource to the Transmission System or the upgrade of an existing Generation Resource (e.g., capacity uprate, etc.). These projects include both Direct Assignment Facilities, which are defined in *Module A of the Tariff* and represent facilities necessary to physically interconnect the Generation Resource to the Transmission System when necessary, as well as Network Upgrades required to facilitate reliable delivery of the output of the Generation Resource to ultimate Load. Generation Interconnection Projects are not cost shared through the Tariff except for Network Upgrades operating at 345 kV and above, where ten (10%) percent of such Network Upgrades costs are cost shared on a postage stamp basis. Generator Interconnection Projects are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement upon execution of the applicable agreement(s).

NOTE: For interconnection customers interconnecting to American Transmission Company's (ATC LLC) transmission systems and meeting certain eligibility requirements, fifty (50%) percent of the Network Upgrade cost is allocated entirely to the ATC LLC pricing zone and the remaining fifty (50%) percent is allocated to affected pricing zones based on subregional and/or postage-stamp allocation rules described under Attachment FF. A similar treatment is applicable to interconnection customers interconnecting to ITC or METC transmission systems and meeting certain eligibility requirements.

2.3.2.6 Transmission Delivery Service Projects

Transmission Delivery Service Projects are New Transmission Access Projects that are defined in *Module A of the Tariff* and described in Module B of the Tariff and represent Network Upgrades required to facilitate long-term firm point-to-point transmission service requests. Transmission Delivery Service Projects are not cost shared through the Tariff, but instead are charged to the Transmission Customer and may be rolled into base rates in accordance with Attachment N of the Tariff. Transmission Delivery Service Projects are assigned to the applicable Transmission Owner(s) in accordance with *Appendix B of the Owners Agreement* upon execution of the applicable agreement(s).

2.3.2.7 Market Participant Funded Projects

Market Participant funded projects (MPFPs) are defined as Network Upgrades fully funded by one or more market participants but owned and operated by an incumbent Transmission Owner. These projects apply to those Network Upgrades that are neither currently included in the MTEP Appendix A nor targeted for approval within the current planning cycle.

2.3.2.8 Targeted Market Efficiency Projects

Targeted Market Efficiency Projects are described under Section 9.4 of the MISO-PJM Joint Operating Agreement and are small, low-cost interregional transmission upgrades with short lead times targeted at locations that consistently show congestion limiting the ability of lower-cost generation to reach load.

TMEP criteria include:

- Project is limited to market-to-market flowgates with PJM,
- Cost of the project must be less the $20 million, and
- Project must be in service by the third summer peak period following approval.

Benefits are based on mitigating average market congestion costs of the previous two years and must cover the project's installed capital cost within four years.

2.4 MTEP Project Database and the MTEP Project Appendices

The MTEP project database is the repository for all transmission projects that have been approved and recommended and all transmission projects categorized as bottom-up projects that have been proposed and/or validated *per Section 2.3 of this BPM*. The project database contains specific information on each transmission project and specific information on each facility associated with each transmission project including, but not limited to, project scope, facility specifications, cost estimates, project drivers, project assignment, scheduled completion dates, status information, and other pertinent information. Furthermore, the annual MTEP report produced for each planning cycle contains two appendices that list transmission projects included in the MTEP project database. MTEP Appendix A includes all projects that have been approved by the MISO Board of Directors in the current or a previous MTEP planning cycle but are not yet in service. MTEP Appendix B includes bottom-up projects needed to address reliability or other localized Transmission Issues that have been validated by MISO and are currently the preferred solution but have not yet been recommended as the final solution. All projects contained in MTEP Appendices A and B are contained within the project database.

2.4.1 MTEP Project Database, Project Table, and Facility Table

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 as described *in Section 4.2.3.1 of this BPM* and facility status data for all projects and associated facilities included in the project database. The MTEP project database does not contain a list of solution ideas proposed by stakeholders to address economic or public policy needs as part of the top-down transmission planning processes. Furthermore, the MTEP project database does not contain any externally driven projects where final commitments have not yet been made to pursue the projects via the applicable executed agreements.

The MTEP project database is used to produce a project table and facility table that are posted publicly. The project table provides pertinent project-level data associated with projects in Appendices A and B. The MTEP facility table provides pertinent facility-level data associated with projects in Appendices A and B. The project table contains the following data, which is a subset of the project data contained within the project database, for each transmission project in the project database:

2.4.1.1 Project Table Data

- **Planning Review Status**: The Planning Review Status of the project. Available choices are:
  - Submitted for Validation in MTEPyy
  - Submitted for Recommendation in MTEPyy
  - Validated in MTEPyy
  - Recommended in MTEPyy
  - Approved in MTEPyy
  - Not Approved in MTEPyy
  - Withdrawn before Approval in MTEPyy
  - Withdrawn after Approval in MTEPyy

where MTEPyy represents MTEP cycle designation, e.g., MTEP14 is for the 2014 MTEP cycle.

- **MISO Planning Region**: The planning region(s) where the transmission project is located. Available choices are *North*, *Central, East, and South*.
- **Project ID Number**: The assigned ID number for the transmission project.
- **Project Name**: The name of the transmission project.
- **Project Description**: A description of the transmission project.
- **Transmission Issue(s) Addressed (System Need Summary)**: A concise description of Transmission Issue(s) addressed by the transmission project.
- **Impacted Transmission Owner(s)**: The Transmission Owner system(s) to which the new transmission facilities associated with the proposed project will interconnect and/or the Transmission Owner system(s) which contain existing transmission facilities that will be modified or upgraded as part of the transmission project.
- **Impacted States**: The state(s) and/or other applicable jurisdiction(s) where the transmission facilities associated with the proposed transmission project are expected to be located. This information is in the facility table and would be summarized in project level reports.
- **Regulatory ID**: The regulatory ID associated with the project to be used by regulatory authorities for their own tracking purposes.
- **Member Project ID**: The ID assigned to the project by the assigned Transmission Owner or assigned transmission developer.
- **Project Category**: The project category associated with the project. Available choices are *Bottom-Up Project, Top-Down Project,* and *Externally Driven Project*.
- **Project Type**: The project type associated with the project. Available choices for projects classified as Bottom-Up Projects are *Baseline Reliability Project* and *Other Project*. Available choices for projects classified as Top-Down Projects are *Multi-Value Project, Market Efficiency Project, and Targeted Market Efficiency Project.* Available choices for projects classified as Externally Driven Projects are *Generator Interconnection Project – Cost Shared, Generator Interconnection Project – Not Cost Shared*, *Transmission Delivery Service Project*, and *Market Participant Funded Project*.
- **Other Project Sub-Category**: The driver(s) associated with a transmission project classified as an Other Project. Available choices include *Clearance, Condition, Distribution, Local Economic, Local Multiple Benefit, Metering, Operational, Performance, Reconfiguration, Relay, Reliability, Relocation, Replacement,* and *Retirement.*
- **Estimated Project Cost**: The estimated cost of the entire project. This is equal to the sum of the estimated costs of each upgraded and/or new facility associated with the

project, where each facility cost is escalated to the expected in-service date for that specific facility. This information is at the facility level and will be summarized in project level reports.

- **Projected In Service Date – First Facility**: The projected in-service date for the first facility to be upgraded or constructed as part of the transmission project. This information is at the facility level and will be summarized in project level reports.
- **Projected In Service Date – Last Facility**: The projected in-service date for the last facility to be upgraded or constructed as part of the transmission project. This information is at the facility level and will be summarized in project level reports.
- **Assigned Transmission Developer**: Indication of the entity (ies) assigned to develop the transmission project and construct and own the associated transmission facilities. For Open Transmission Projects, this field will be populated with the Selected Transmission Developer when determined and will be blank prior to project award. For Open Transmission Projects where a regulatory process has determined that an existing Transmission Line Facility must be upgraded to include additional transmission circuits and Section VIII of Attachment FF of the tariff requires that this upgrade be jointly developed by the incumbent Transmission Owner and the Selected Transmission Developer, this field will include both the Selected Transmission Developer and the incumbent Transmission Owner(s). For all other transmission projects, this field will be populated with Transmission Owner(s) that have been assigned to construct the facilities in accordance with Appendix B of the Owners Agreement.

The facilities table contains the following data, which is a subset of the facility data contained within the project database, for each facility associated with each transmission project included in the project database:

2.4.1.2 Facility Table Data

- **Impacted Transmission Owner(s)**: The impacted transmission owner(s) for the specific facility in question.
- **Project ID Number**: The Project ID number associated with the parent project.
- **Facility ID Number**: The assigned ID number associated with the facility in question.
- **Expected ISD**: The expected in-service date for the facility in question.
- **Member Project ID**: The ID assigned to the parent project by the assigned Transmission Owner or assigned transmission developer.
- **From Sub**: If a new transmission line or transmission line upgrade, this field represents one of the two substation terminals (where substation terminal could also represent

the midpoint of a three terminal transmission line). If substation equipment, a new substation, or a substation upgrade, this field represents the name of the substation.

- **To Sub or Major Equipment Type**: If a new transmission line or transmission line upgrade, this field represents one of the two substation terminals (but not the same terminal specified in "From Sub". If substation equipment, a new substation, or a substation upgrade, this field represents the major equipment type here, for example, transformer, capacitor, reactor, DVAR.
- **Circuit ID**: A unique ID number to track multiple transmission circuits on a common transmission line, multiple transformers, or other series equipment between two or more common Buses within a specific substation, or multiple shunt equipment connected to a common Bus within a substation (e.g., capacitor banks, etc.).
- **Max kV**: If a power transformer, this field represents the nominal operating kV of the highest voltage winding. If a multi circuit transmission line with circuits that operate at different voltages, this field represents the nominal operating kV of the highest voltage circuit. Otherwise, this field represents the nominal operating kV associated with the transmission facility.
- **Min kV**: If a power transformer, this field represents the nominal operating kV of the lowest voltage winding (tertiary windings excluded unless electrically connected to transmission facilities). If a multi circuit transmission line with circuits that operate at different voltages, this field represents the nominal operating kV of the lowest voltage transmission circuit (distribution circuits and communication circuits excluded). Otherwise, this field represents the nominal operating kV associated with the transmission facility.
- **Normal Facility Rating**: The normal continuous MVA or Mvar rating for the summer season.
- **Maximum Facility Rating**: The highest emergency MVA rating associated with the facility for the summer season.
- **Impacted State(s)**: Each state (or other jurisdiction) in which the facility is located or expected to be located.
- **Miles Upgraded**: Associated only with existing transmission line facilities or existing right-of-way. Represents the total number of miles of upgrade made to an existing transmission line facility.
- **Miles New**: Associated only with new transmission line facilities. Represents the total number of miles of new facility construction on new right-of-way.
- **Facility Status**: The current status associated with the transmission facility. Available choices are *Proposed, Planned, Milestone 1, Milestone 2, Milestone 3, Milestone 4:*

Under Construction, Milestone 5: In service, Under Construction, In Service, and Withdrawn. This information is at the facility level and will be summarized in project level reports.

- **Estimated Cost**: The *Estimated Cost* of the facility escalated to the expected in-service date for the facility.
- **MISO Functional Control**: A binary field that indicates whether or not the facility will be under the functional control of MISO. If "*App H*", this facility will be placed under the functional control of MISO. If "*App G*", this facility will not be placed under *MISO Functional Control* and is under an Agency Agreement.

2.4.2 Project Table and Facility Table Status Fields

The project table contains a planning review status field and the facility table includes a facility status field. These fields are discussed in more detail below.

2.4.2.1 Planning Review Status Field

This field represents the status of the projects with regard to planning review activities as follows:

- **Submitted for Validation**: Only bottom-up projects may have a planning review status of *Submitted for Validation*. This status applies to any bottom-up project *type A* by MISO staff or a Transmission Owner that has not yet been validated by MISO.
- **Submitted for Recommendation**: Only bottom-up projects may have a planning review status of *Submitted for Recommendation*. This status applies to any bottom-up project *Submitted for Recommendation* by MISO staff or a Transmission Owner that has not yet been validated by MISO.
- **Validated**: Only bottom-up projects may have a planning review status of *Validated*. This status applies to any bottom-up project that has been *Validated* by MISO to be a prudent solution to an identified Transmission Issue but has not yet been recommended for approval.
- **Recommended**: This status applies to any transmission project that is being *Recommended* by MISO for approval by the MISO board of directors in the current MTEP cycle but has not yet been approved by the MISO board of directors.
- **Approved**: This status applies to any transmission project that has been approved for construction by the MISO board of directors.
- **Not Approved**: This status applies to any transmission project that was not successfully validated or recommended by MISO staff. The project's associated facilities would also have a *Withdrawn* facility status.
- **Withdrawn before Approval**: This status applies to any transmission project that has been *Withdrawn before Approval*. The project would remain in the project database

with this status. The project's associated facilities would also have a *Withdrawn* facility status.

- **Withdrawn after Approval**: This status applies to any transmission project that has been *Withdrawn after Approval*. The project would remain in the project database with this status. The project's associated facilities would also have a *Withdrawn* facility status.

2.4.2.2 Facility Status Field

This field represents the overall status of a specific facility as follows:

- **Proposed**: Only facilities associated with bottom-up projects may have a facility status of proposed. Facilities associated with bottom-up projects with a Planning Review Status of *Submitted for Validation, Submitted for Recommendation, or Validated* will have a facility status field set to *Proposed*.
- **Planned**: Facilities associated with bottom-up and top-down transmission projects that have a Planning Review Status of *Recommended* but have not yet met cost estimating Milestone 1 pursuant *to Section 4.2.3.1 of this BPM* should have a facility status of *Planned*. This status also applies to externally driven projects that have a Planning Review Status of *Recommended* or *Approved* but are not yet *Under Construction*.
- **Milestone 1**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 1 pursuant *to Section 4.2.3.1 of this BPM*, but have not yet achieved Milestone 2. Milestone 1 is the milestone associated with the completion of the July subregional planning meetings in the current MTEP cycle.
- **Milestone 2**: Applies to bottom-up and top-down transmission projects. Applies to all applicable transmission projects with facilities that have achieved milestone 2 pursuant *to Section 4.2.3.1 of this BPM* but have not yet achieved milestone 3. Milestone 2 is the milestone defined to be just prior to approval of the project by the MISO board of directors.
- **Milestone 3**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 3 pursuant *to Section 4.2.3.1 of this BPM* but have not yet achieved Milestone 4. Milestone 3 is the milestone where long lead materials have been ordered.
- **Milestone 4 - Under Construction**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 4 pursuant to *Section 4.2.3.1* of this BPM but have not yet achieved Milestone 5. Milestone 4 is the milestone where construction has commenced.
- **Milestone 5 - In Service**: Applies to all bottom-up and top-down transmission projects with facilities that have achieved Milestone 5 pursuant *to Section 4.2.3.1 of this BPM*,

which is the milestone where the transmission project has been completed and all associated facilities are *In Service*.

- **Under Construction**: Facilities associated with externally driven projects that are under construction should have a facility status of *Under Construction*.
- **In Service**: Facilities associated with externally driven projects that have been placed in service should have a facility status of *In Service*.
- **Withdrawn**: Facilities that have been withdrawn from projects or are associated with projects that have been cancelled or have a Planning Review Status of *Not Approved,* should have a facility status of *Withdrawn*.

2.4.3 MTEP Appendix A

The MTEP report associated with each MTEP cycle will contain an Appendix A that lists all transmission projects that have been approved in the current MTEP cycle or have been approved in a previous MTEP cycle but are not yet fully implemented (i.e., all facility upgrades and/or new facilities associated with the project are not yet in service). It is important to note that MTEP appendices associated with a specific MTEP cycle are not official until the MISO board approves the MTEP report and associated recommendations. With this in mind, the draft MTEP Appendix A prior to MTEP report approval contains all projects within the transmission project database that have a Planning Review Status of either *Recommended* or *Approved.* In developing the draft MTEP Appendix A, the starting point is MTEP Appendix A from the previous MTEP cycle, which includes all transmission projects with a Planning Review Status of Approved upon approval of the previous MTEP report. Any transmission project included in the previous MTEP Appendix A that has been fully implemented (i.e., all facilities in service) or cancelled will be removed from the current draft MTEP Appendix A. Any transmission project approved since the conclusion of the previous MTEP cycle, including out-of-cycle transmission projects approved since the conclusion of the previous MTEP cycle, which have a current Planning Review Status of Approved, are considered in MTEP Appendix A and will be added to the current draft MTEP Appendix A. Any transmission project recommended for approval since the conclusion of the previous MTEP cycle are not yet included in MTEP Appendix A, but will be added to the draft MTEP Appendix A for consideration by the MISO Board. Upon approval of a specific MTEP report and associated recommendations, all projects in MTEP Appendix A of that MTEP report are considered approved and the Planning Review Status will be set to Approved.

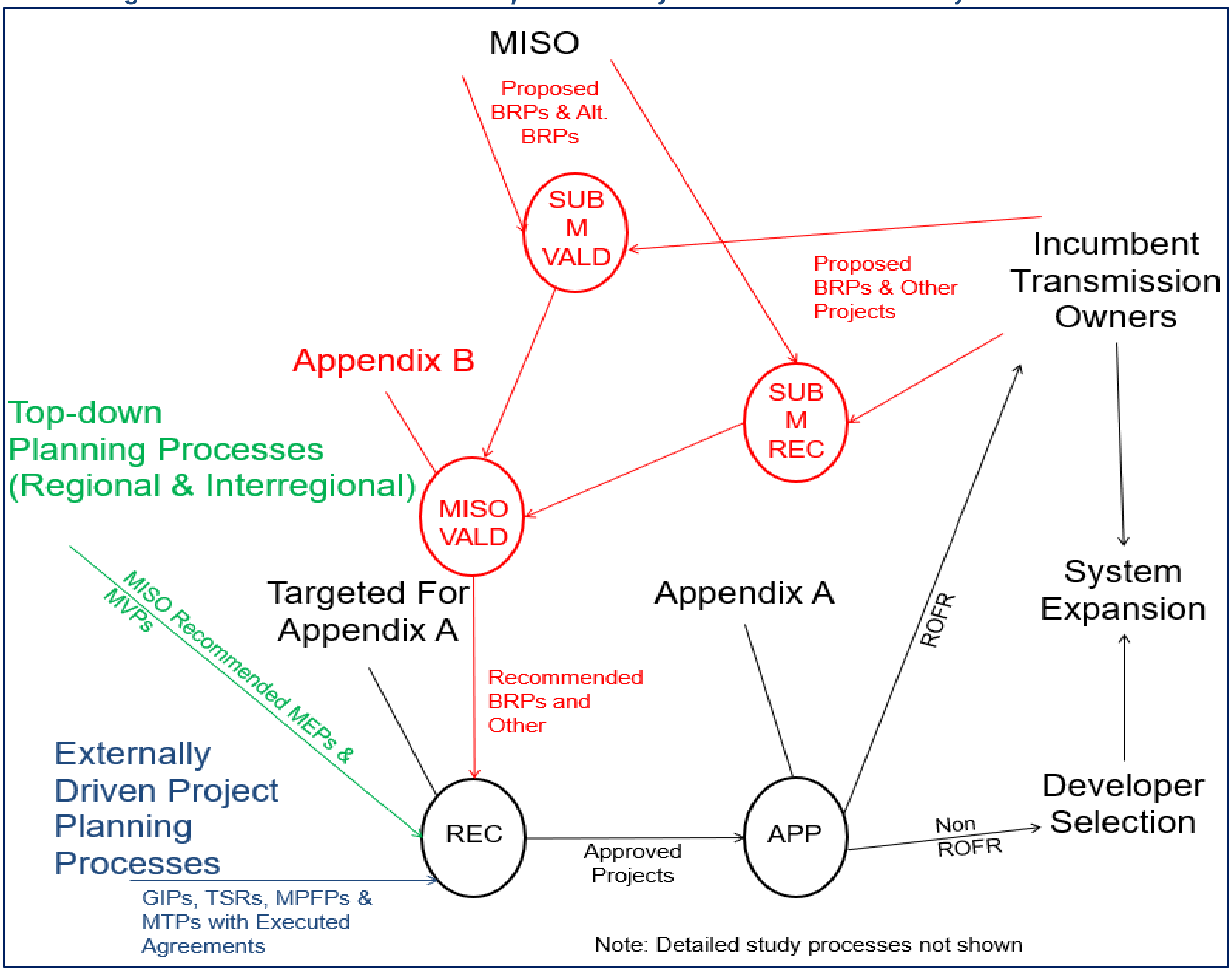
2.4.4 MTEP Appendix B

The MTEP report associated with each MTEP cycle will contain an Appendix B that lists all bottom-up projects that have been validated by MISO as the preferred solution to address an identified need based on current information and forecasts, but where it may be prudent to defer the final recommendation of a solution to a subsequent MTEP cycle (e.g., the preferred project does not yet need a commitment based on anticipated lead time and required in service dates and there is some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions, etc.). MTEP Appendix B is limited to bottom-up projects only (i.e., Baseline Reliability Projects and Other Projects). MTEP Appendix B contains all bottom-up Projects within the transmission project database that have a Planning Review Status of *Validated.* In developing the MTEP Appendix B, the starting point is MTEP Appendix B from the previous MTEP cycle. Any transmission project included in the previous MTEP Appendix B that i) will be recommended for approval in the current MTEP cycle, ii) is determined to no longer be the best or most prudent solution to an identified need, or iii) was previously included to address a specific need or needs that no longer exist will be removed from the current MTEP Appendix B. After this step is completed, any new bottom-up project submitted by a Transmission Owner or MISO in the current MTEP cycle to address an identified need that has been validated by MISO to be the preferred solution based on the most current information and forecasts, but that is not yet ready for recommendation, will be added to the current MTEP Appendix B.

2.4.5 Submission of Bottom-up Projects into the MTEP Project Database

Transmission Owner(s) will submit bottom-up projects into the MTEP project database by September 15th of each year for the MTEP cycle associated with the following calendar year or as out-of-cycle projects in accordance *with Section 6.1 of this BPM*. Bottom-up projects, which must be classified as either Baseline Reliability Projects or Other Projects, must be submitted with a Planning Review Status of *Submitted for Validation* or *Submitted for Recommendation*. If the Transmission Owner determines that approval of the submitted transmission project is required in the current MTEP cycle, then the Transmission Owner will specify a Planning Review Status of *Submitted for Recommendation*. If the Transmission Owner determines that approval of the transmission project is not required in the current MTEP cycle, then the Transmission Owner will specify a Planning Review Status of *Submitted for Validation*. If the project is required to comply with NERC TPL standards, the Transmission Owner should designate the submitted project as a Baseline Reliability Project, regardless of the assigned Planning Review Status. *Figure 2.4.5-1, below,* illustrates how bottom-up projects move through the project database and MTEP Appendices from the standpoint of planning review status.

Figure 2.4.5-1: Submission of Top-Down Projects into the MTEP Project Database



2.4.6 Submission of Top-Down Projects into the MTEP Project Database

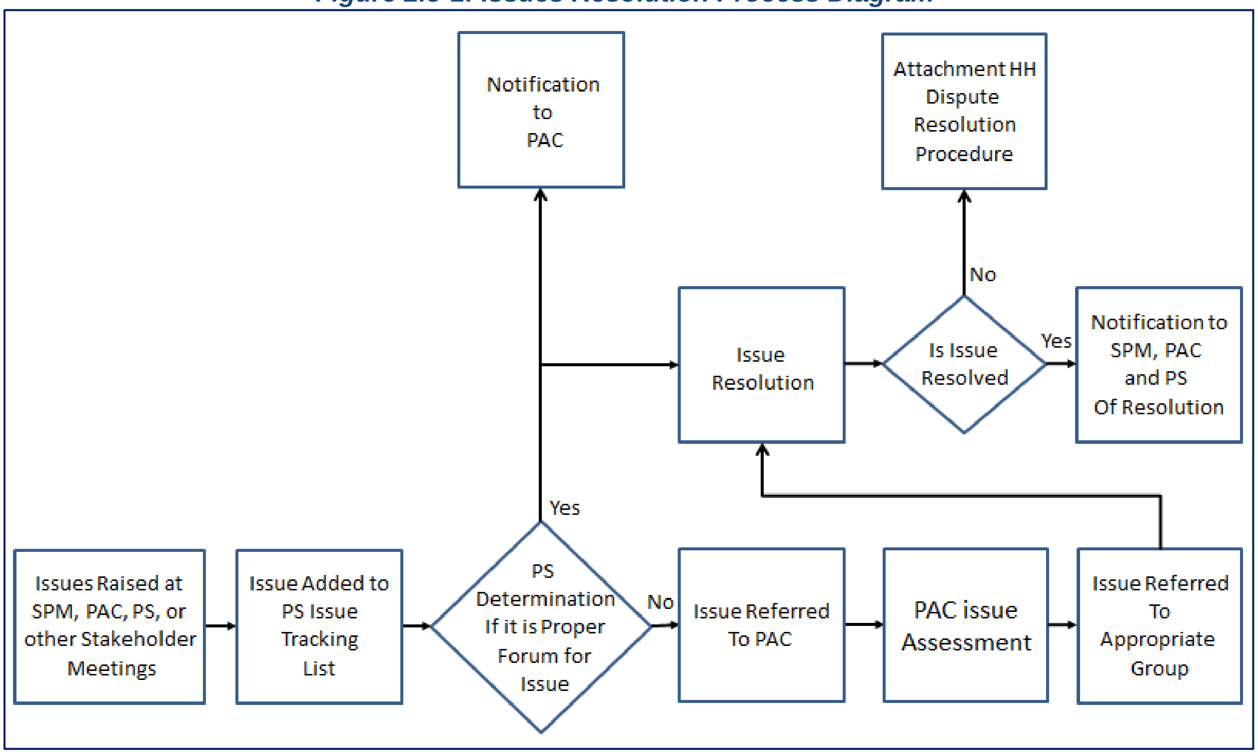
Only MISO staff will submit regional and interregional top-down projects into the MTEP project database at such a time when a decision has been made in the planning process to formally recommend the project for approval by the MISO board of directors. All top-down projects will be submitted to the MTEP project database with a Planning Review Status of *Recommended*. No top-down projects will be permitted to have a Planning Review Status of Submitted for Validation, Submitted for Recommendation, or Validated. Top-down projects include interregional, regional, and subregional Market Efficiency Projects and Multi-Value Projects. *Figure 2.4.5-1* illustrates how top-down projects move through the project database and MTEP Appendices from the standpoint of planning review status.

2.4.7 Submission of Externally Driven Projects into the MTEP Project Database

MISO staff or Transmission Owner(s) will submit externally driven projects into the MTEP project database at such time when all conditions, including but not limited to execution of applicable agreements, have been satisfied for formal recommendation of the project for approval by the MISO board of directors. All externally driven projects will be submitted to the MTEP project database with a Planning Review Status of Recommended. No externally driven projects will be permitted to have a Planning Review Status of Submitted for Validation, Submitted for Recommendation, or Validated. *Figure 2.4.5-1* illustrates how externally driven projects move through the project database and MTEP Appendices from the standpoint of planning review status.

2.5 Issues Resolution Process Prior to Tariff Dispute Resolution Procedure (Attachment HH)

Figure 2.5-1: Issues Resolution Process Diagram



During the stakeholder review (i.e., SPM, PS, or PAC) of results and preferred solutions to Appendix B projects or after cost responsibilities for projects to be moved to Appendix A are determined an issue with the project may be raised and at that point the issue will follow the process illustrated *in Figure 2.5-1 above*.

After an issue has been raised about a project the next step will be to determine which party is the correct one to address the issue. The Planning Advisory Committee will use the following general guidelines to determine what group addresses the issue:

- High-level policy related issues will be addressed by the PAC
- Technical issues will be directed to the Planning Subcommittee
- Ad Hoc Task Force will be formed for issues that require three (3) or more Days of work from individuals outside the committee structure (i.e. market operations, rate experts, etc.) or additional expertise on planning issues not readily available in the committee.
- Short-term work group may be formed to develop proposals to address an issue and bring that work back to the PAC or PS for consideration.

Once an issue has been referred to the proper working group (including a temporary short-term task force) the issue will be resolved following MISO Governance Process. The process will include the following:

- Working sessions, including research and data gathering will occur for the timeframe necessary to develop a recommendation (motion) for resolution to the issue.
- A motion, based on the outcome of the working sessions, will be presented and seconded.
- Debate will occur on the resolution.
- Committee participants will vote on the resolution.
- That recommendation will be presented to the parent committee(s) (i.e., SPM, PAC, or PS) and MISO. Recommendations are non-binding and will represent the advice of the committee to affected parties.

In the event that affected parties are not satisfied with the recommended resolution or an agreed upon resolution cannot be reached the affected parties may move to the Dispute Resolution Procedure in Attachment HH of the Tariff.

2.6 General Process Responsibilities

2.6.1 Transmission Provider (MISO)

MISO is the NERC Planning Authority for its Member footprint, and performs regional planning in accordance with FERC Planning Principles delineated in Order 890. These Planning Principles provide mechanisms to ensure that the regional planning process is open, transparent, coordinated, includes both reliability and economic planning considerations, and includes mechanisms for equitable cost sharing of expansion costs. MISO, through the regional planning process, integrates the local planning processes of its Member companies and the advice and guidance of stakeholders into a coordinated regional transmission plan and identifies additional expansions as needed to provide for an efficient and reliable transmission system that delivers reliable power supply to connected Load customers, expands trading opportunities, better integrates the grid, alleviates congestion, provides access to diverse energy resources, and enables state and federal energy policy objectives to be met. MISO planning staff will produce regional plan reports no less frequently than biennially and will make such plans publicly available on the MISO web site.

MISO planning staff is responsible for conducting the regional planning process, including the organization and facilitation of stakeholder meetings and committees that advise the planning staff and the Transmission Provider Board.

In producing the integrated and coordinated regional transmission plan, MISO adheres to the provisions of the tariff and the Business Practices Manuals, including this BPM. MISO planning staff is responsible for establishing the timelines and requirements for, and performing the actions necessary to complete each of the key milestones below in the regional planning process:

- Model development for MISO needs and NERC MOD-032
- Testing models against reliability and economic planning criteria
- Collaborative development of possible solutions to identified issues
- Selection of preferred solution
- Determination of funding and cost responsibility
- Monitoring progress on solution implementation

MISO planning staff is responsible for developing regional planning models and for providing the requirements and timelines for exchange of information with Load Serving Entities (LSE is Tariff defined term), Generation Owners, Transmission Customers, Transmission Owner(s), and neighboring Transmission Entities necessary for model development. Such information includes Load Forecasts and geographic distribution of such forecasts on a transmission substation basis, generating resource commitments, Generator operational and economic performance data, and existing and proposed transmission upgrades. MISO planning staff is responsible for making models available for stakeholder review with appropriate protection of CEII and commercially sensitive data.

MISO planning staff is responsible for developing a Study Plan and arranging for stakeholder meeting(s) with the Subregional Planning Meetings, Planning Subcommittee, and Planning

Advisory Committee for collaborative input and refinement of the planning scope, project definition and purpose, work assignments and responsibility, scheduling, cost analysis, alternatives, and assumptions.

MISO planning staff is responsible for testing regional models to identify performance of the models against national reliability standards, and for identifying opportunities for economic expansions that meet established economic planning criteria, and that are necessary to efficiently meet state and federal energy policy objectives over short, intermediate, and long-term planning horizons (1-5, 6-10, 11-20 years). MISO planning staff is responsible for evaluating alternative solutions to identified needs, and for working with Transmission Owner(s) and other stakeholders to identify recommended solutions. Identification of recommended solutions includes consideration of a variety of factors including urgency of need, energy policy mandates, and comparisons amongst alternatives over the planning horizon of initial investment costs, operating performance, robustness of the solution, longevity of the solution provided, and performance against other economic and non-economic metrics as developed with stakeholders.

MISO planning staff evaluates recommended projects for cost allocation in accordance with the Tariff provisions, and for presenting the results of cost allocation calculations to stakeholders for review and comment. MISO planning staff provides projections of annual cost responsibilities by pricing zone associated with cost sharing.

MISO planning staff is responsible for directing the preparation of a preliminary MTEP report proposing new projects, modifications to existing projects and proposing alternative solutions to deficiencies identified in the assessment process, for presenting the highlights of the report to stakeholders, and for distributing the report to stakeholders for written comments.

MISO planning staff is responsible for preparing the final draft of the comprehensive MTEP Plan. MISO planning staff is responsible for presenting the comprehensive MTEP Plan to the Transmission Provider Board (Biennial Plan and annual update reports) for approval. MISO planning staff is then responsible for posting the Transmission Provider Board-certified plan on the MISO website and issuing it to regulatory authorities and other requesting parties and for monitoring and reporting the MISO construction implementation process.

Finally, to the extent assistance is needed by the affected Transmission Owner(s) or designated entities in justifying the need for and obtaining certification of any facilities required by the approved MTEP, MISO shall prepare and present testimony in any proceedings before state or federal courts, regulatory authorities, or other agencies as may be required.

2.6.2 Transmission Owner(s)

In accordance with the ISO Agreement, each Transmission Owner engages in local system planning in order to carry out its responsibility for meeting its respective transmission needs in collaboration with MISO and subject to the requirements of applicable state law or regulatory authority. In meeting its responsibilities under the ISO Agreement, the Transmission Owner(s) may, as appropriate, develop and propose plans involving modifications to any of the Transmission Owner's transmission facilities which are part of the Transmission System. In developing proposed plans, the Transmission Owner(s) will adhere to any applicable state or local regulatory planning processes. Proposed plans developed by the Transmission Owner(s) for potential inclusion in the regional plan are evaluated and discussed with stakeholders through the annual regional planning process as described further in this BPM.

Each Transmission Owner must submit to the Transmission Provider on an annual basis and at a time to be determined by the Transmission Provider, which shall be prior to the beginning of each regional planning cycle, all proposed transmission plans for both transferred and Non-transferred Transmission Facilities. Transmission Owner(s) participate in Subregional Planning Meetings (SPMs) in their respective planning subregions as per the Transmission Provider's meeting schedule, and in regularly scheduled Planning Subcommittee meetings. Transmission Owner(s) may be requested by MISO planning staff to present their proposed projects to stakeholders at SPMs or Planning Subcommittee meetings and discuss the justifications, alternatives, estimated costs, expected service dates, and other aspects of proposed projects with stakeholders. In the alternative, MISO planning staff may present this information to stakeholders, and the Transmission Owner(s) are required to provide representatives that can support these discussions and respond to stakeholder questions about project details.

Transmission Owner(s) are responsible for providing modeling data to MISO as Planning Coordinator per NERC MOD-032 standard. Transmission Owner(s) are responsible for supporting and participating in the development of MISO and Inter-RTO planning models. The Transmission Owner(s) will be responsible for preparing and updating any detailed power system models they may need for their own use, or for meeting modeling requirements of Regional Entities or other planning groups. Transmission Owner(s) are encouraged to use the same, or very nearly the same models for their own planning purposes as developed collaboratively with MISO in order to maintain maximum consistency between planning results obtained from alternative models of the same planning horizon.

Transmission Owner(s) are responsible for applying their expert knowledge of the strengths and weakness of their respective transmission systems to the evaluation of all projects in the MISO Plan affecting their respective transmission systems.

Finally, Transmission Owner(s) are responsible for the good faith implementation including land acquisition, regulatory permitting and construction of Transmission Provider Board-certified expansion projects.

2.6.3 Generation Owners

Generation Owners are responsible for providing modeling data to MISO as the Planning Coordinator in accordance with NERC MOD-032 standard. This data is used by MISO and Transmission Owner(s) for Load flow, short circuit, dynamic stability and other future studies as needs arise. Generation Owners are responsible for meeting regulatory reliability standards and reliability planning clauses in their agreements with Transmission Owner(s) and Service Agreements, as applicable. The facility plans developed with the Generation Interconnection Studies and Generator Agreements will be an essential part of MISO Transmission Owner expansion plans to enable competitive generator markets. Generation Owners are encouraged to participate in the planning process through the stakeholder input and review phases of the planning process.

2.6.4 Load Serving Entities

Load Serving Entities (as defined in *Module A of the Tariff*) are responsible for providing modeling data to MISO as the Planning Coordinator per NERC MOD-032 standard. Load Serving Entities will be responsible for annually making and providing MISO with forecasts of Network Load in accordance *with Section 29.2 and Module E of the Tariff* and MISO's MOD-032 Model Data Requirements & Reporting Procedures. This includes the requirement to provide the amount and location of interruptible Load and the needed Network Resource information. Firm Transmission Service Customers are responsible for identifying POR/POD information as required in the MISO OASIS automation system and Tariff reservation and scheduling requirements. LSEs are encouraged to involve themselves in the MISO planning process by participating in the stakeholder input and review phases of the planning process.

2.6.5 Transmission Customers

Transmission Customers will have the same planning responsibilities as LSEs. Accurate Load Forecasts and assistance in modeling multi-regional Load transfers are an integral requirement in the determination of future system expansion plans. Facility Studies conducted to meet Transmission Customer Long Term Firm Transmission Service request and reservations are a vital part of MISO Transmission Owner expansion plans. Transmission Service Customers are encouraged to involve themselves in the MISO planning process by participating in the stakeholder input and review phases of the planning process.

2.6.6 Other Regional Transmission Operators (RTOs)

The participating RTOs under an inter-RTO cooperation process will be responsible for identifying Network Upgrades through their respective organization procedures and their proposed Integrated Regional Expansion Plans including Generator Interconnection Studies that significantly impact one another. The Joint RTO Transmission Planning Committee and Subcommittees cooperatively determine and facilitate any required Coordination Studies. The affected RTOs use their respective organizational planning procedures (MTEP collaborative process) to complete the coordination studies. The proposed consolidated facilities resulting from the coordination expansion studies are presented to the Joint RTO transmission planning and relevant subcommittees for review. The resulting recommended Inter-RTO coordinated expansion plans are compiled in a report. MISO Inter-RTO coordinated facilities are combined with MISO Intra-MISO expansion plans. The resulting consolidated plan will be submitted for approval to the Transmission Provider Board for certification. After certification by the participating RTOs, construction programs will commence to implement their respective facility responsibilities. The Intra-MISO and Inter-RTO facilities will be constructed as required in the MISO Agreement as well as MISO and Transmission Owner(s) Tariffs. All facility expansions must be effectively coordinated and expeditiously constructed. Further, Inter-RTO facilities require additional Inter-RTO coordination.

2.6.7 Other Stakeholders (Including State Regulatory Commissions)

Stakeholders, including State Regulatory Commissions, provide MISO with critical stakeholder input and review of transmission expansion projects in the MTEP Plan as they are developed and updated. The State Commission inputs related to projections of Load growth, resource requirements, transmission siting authority and environmental concerns assist MISO in the development of realistic transmission expansion projects and alternatives to meet the needs of their citizens as well as neighboring regions. Since all MISO planning meetings are open to all stakeholders, stakeholders are responsible for attending as their interest dictates. Communication avenues such as electronic mail and the MISO website, along with open discussion periods in scheduled meetings, allow stakeholders to effectively participate in the MTEP planning process.

2.7 Treatment of Confidential Data

The Transmission Provider will utilize a Non-Disclosure and Confidentiality Agreement (NDA) to address sharing of Critical Energy Infrastructure Information (CEII) transmission planning information. FTP sites containing such information will require such agreements to be executed to obtain access. Stakeholder meetings at which CEII information will be available will be noticed to email exploders that will require execution of NDAs for inclusion. In the alternative, such meetings will be structured to have separate discussion of issues involving CEII data only with participants that agree to execute the NDA. Confidential information related to economic (e.g., congestion) studies, as well as CEII, is sensitive information which must remain confidential. The Transmission Provider will use generic (publicly available) cost information from industry sources in the economic studies to prevent accidental release of confidential information and promote a truly open process because results of economic studies are available to all interested parties.

2.8 OMS Committee Role in Transmission Planning

The Organization of MISO States (OMS) Committee, as defined in the Owners Agreement and the Tariff, may participate, at its discretion, in the MISO transmission planning process throughout each MTEP planning cycle. Specifically, the OMS Committee may provide input and feedback on the following items:

- Planning Principles
- MTEP Scope
- MTEP Futures
- MTEP Process Issues
- MTEP Final Recommendations

2.8.1 OMS Committee Input on MTEP Guiding Principles Provided by the Transmission Provider Board

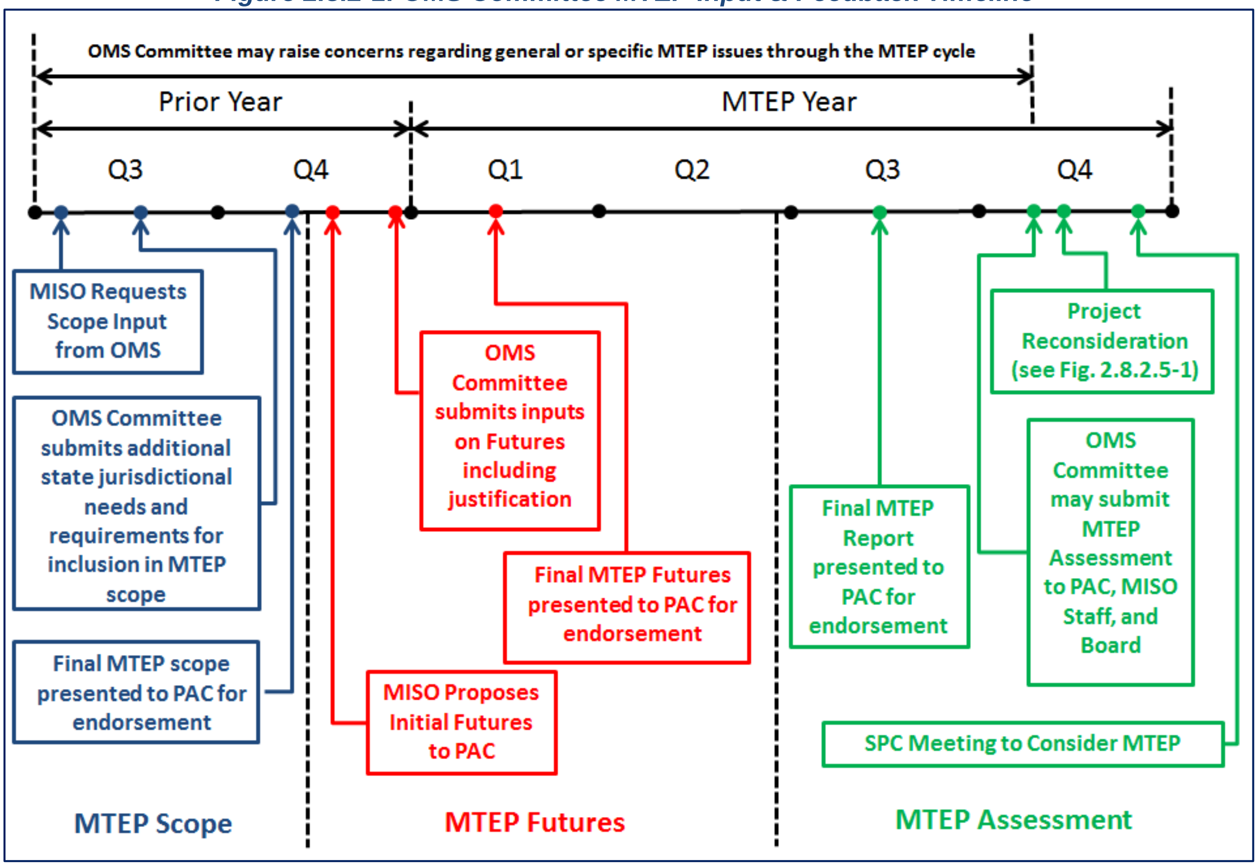
As listed *in Section 2.1 of this BPM*, the Transmission Provider Board has adopted MTEP Guiding Principles to guide the transmission planning process. The System Planning Committee (SPC) of the Transmission Provider Board typically reviews these principles every other year and may make adjustments if deemed necessary as circumstances evolve. The OMS Committee will have the opportunity to provide input and feedback to the System Planning Committee of the Transmission Provider Board and to address the SPC in a public meeting every other year regarding the MTEP Guiding Principles provided by the Transmission Provider Board including, but not limited to, recommendations to add, modify, or remove specific MTEP Guiding Principles.

MISO will biennially solicit comments, suggestions, or recommendations regarding the planning principles from the OMS Committee and other sectors of the Planning Advisory Committee (PAC) by a date determined by MISO. MISO will provide the OMS Committee a forty-five (45) day notice of this date. This biennial review process will align with review by the SPC at their February meeting.

2.8.2 OMS Committee Input and Feedback on MTEP

Per Section I.B of Attachment FF of the Tariff, the OMS Committee may submit input into and feedback on each MTEP cycle as illustrated *in Figure 2.8.2-1, and as further described below*.

Figure 2.8.2-1: OMS Committee MTEP Input & Feedback Timeline



2.8.2.1 OMS Committee Input on MTEP Scope of Study

Each MTEP cycle begins on June 1 of the year preceding the calendar year designation of the specific MTEP cycle. The scope of study, (Scope) of a specific MTEP cycle, while fixed in part by provisions of the Owners Agreement, Tariff, and Business Practices Manuals, may have additional items added as necessary from cycle-to-cycle. The development of the MTEP scope normally begins with the Subregional Planning Meetings scheduled in June of the year prior to the calendar year designation of the MTEP, and then is rolled up to the Planning Subcommittee in August of that year and finally to the Planning Advisory Committee in September or October of that year where the Planning Advisory Committee will provide feedback and recommendations to MISO. The final scope of a specific MTEP cycle will typically be established by November of the year prior to the calendar year designation of the MTEP cycle.

The OMS Committee may identify items, including additional state jurisdictional needs or requirements, to be included in the scope for a specific MTEP cycle and will forward those items to the Transmission Provider within forty-five (45) Days of the date when MISO requests this information[6]. MISO will typically request this information from the OMS Committee on July 1 of the year prior to the calendar year designation for the MTEP cycle in question so that the OMS Committee may assemble recommendations for MTEP scope items in parallel with the development of scope items via the Subregional Planning Meetings. This allows for MISO to consider MTEP scope recommendations from the Subregional Planning Meetings, the Planning Subcommittee, and the OMS Committee in developing the draft MTEP scope to be submitted to the Planning Advisory Committee at the September or October meeting in the year prior to the calendar year designation for the MTEP in question. MISO will finalize the MTEP scope of study no later than the December PAC meeting.

2.8.2.2 OMS Committee Inputs on Futures

As part of the annual Futures discussions conducted with the Planning Advisory Committee each year, the OMS Committee will have the opportunity to submit suggestions and/or recommendations to MISO regarding the Futures that will be used to support planning analyses, where Futures represent multiple future policy and economic scenarios that drive modeling inputs and assumptions used in the development of the MTEP and related appropriate cost/benefit analyses with respect to certain projects that are not proposed strictly for reliability. Such suggestions and recommendations may address both what Futures will be modeled as well as inputs, parameters and values of the uncertainty variables applied to these Futures. Suggestions

[6] In addition to providing input to the scope of studies for a specific MTEP planning cycle, the OMS Committee and other stakeholders will be able to provide scope input on specific studies and initiatives within the MTEP cycle as they are developed and continue to evolve throughout the cycle.

and recommendations on the proposed futures must be forwarded to MISO within sixty (60) Days after MISO initially proposes the Futures. Suggestions and recommendations on inputs, parameters, values of the uncertainty variables and subsequent modifications, shall be forwarded to MISO within fourteen (14) Days after MISO provides an initial proposal on the values of the uncertainty variables. MISO will present this information as part of the annual Futures discussions conducted with the Planning Advisory Committee. MISO will have the option of incorporating such suggestions and/or recommendations in the development and Application of the MISO selected Futures or of performing supplemental analyses in parallel by applying the assumptions developed from the OMS inputs. In the event the suggestions and/or recommendations requested by OMS are not incorporated into the MISO selected Futures, supplemental OMS analyses shall be provided to the Planning Advisory Committee. Should such requests result in an undue burden on MISO, then MISO will negotiate with the OMS Committee to reach an acceptable compromise that is satisfactory to both parties given the timing, resource, and other constraints imposed on MISO in performing such analyses.

NOTE: In a typical planning year, initial Futures proposals are presented at the September or October Planning Advisory Committee meetings and uncertainty variables are typically detailed at the November and/or December Planning Advisory Committee meetings. Final values for some uncertainty variables cannot be determined until actual modeling begins and it may be necessary to initially provide an approximate value to OMS.

2.8.2.3 Ongoing OMS Committee Feedback on General or Specific MTEP Process Issues

During an ongoing MTEP cycle, the OMS Committee may raise concerns to the MISO staff regarding general or specific issues regarding the MTEP process. The MISO staff will respond to the OMS Committee in a timely manner. If issues cannot be resolved, the OMS Committee may forward concerns to the Planning Advisory Committee and, if requested by the OMS Committee, the Transmission Provider Board, to be considered when taking action to endorse or approve the final MTEP plan. Feedback regarding general or specific issues provided by OMS during an MTEP cycle must be received by the MISO by the latter of sixty (60) Days from when the initial draft of the MTEP report is posted or October 31 of the year corresponding to the calendar year designation of the MTEP, to enable MISO sufficient time to respond to such concerns.

The OMS Committee and other stakeholders may also request, and shall receive from MISO staff as promptly as reasonably possible given analysis timelines and result availability, (a) pricing zone-by-pricing zone cost analyses, and (b) state-by-state, or local resource zone-by-local resource zone project or project portfolio cost and benefit analyses, as appropriate, with respect to any project or project portfolio where the cost allocation is premised in whole or in part on economics, but not including projects proposed strictly for reliability purposes. The analyses furnished shall be of a similar quality to those furnished to transmission owning stakeholders, and shall conform to applicable engineering, economic or other planning standards or practices delineated in NERC standards, the Tariff, and MISO BPMs.

2.8.2.4 OMS Committee Assessment of Overall MTEP Planning Cycle

At the end of an MTEP cycle when the final MTEP plan has been published, but prior to consideration by the Transmission Provider Board, the OMS Committee will have an opportunity to perform, at their discretion, an assessment, in parallel with the assessment performed by the Planning Advisory Committee, of the specific MTEP planning cycle including the overall planning process, models, inputs, and assumptions used within the planning cycle. Should the assessment identify specific concerns, the results of the assessment, including the identified concerns, will be forwarded to the Planning Advisory Committee, the MISO Staff, and the Transmission Provider Board within thirty (30) Days of the date when the final draft of the MTEP report is posted (which is typically in September of each year).

2.8.2.5 OMS Committee Recommendations to Reconsider Specific Project Recommendations

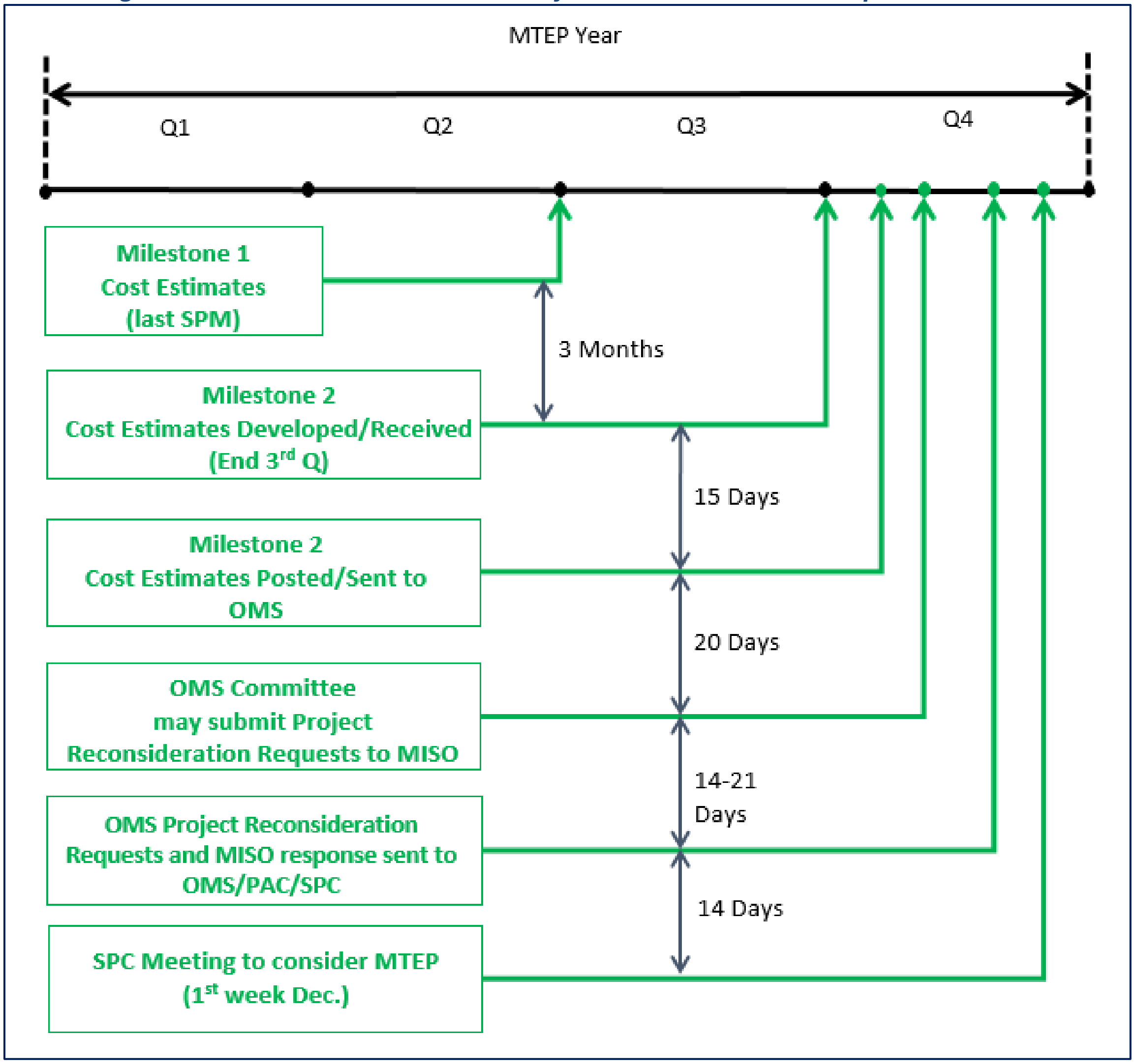
For any project not yet approved by the MISO Board that is eligible to receive regional cost allocation under Attachment FF being recommended for Appendix A, either within a portfolio or individually, and that is not a Generation Interconnection Project, the OMS Committee may, with a sixty-six (66%) percent or greater majority vote by the OMS Board, request such project to be reconsidered by the MISO staff if the OMS Committee actively participated in the planning process for the MTEP cycle or portfolio planning cycle in question and at least one of the following two conditions has been satisfied:

- The proposed project, a proposed alternative to the proposed project, including an alternative combination of facilities for the proposed project, was not vetted within the appropriate planning stakeholder groups (e.g., subregional planning meetings, technical study task forces, technical study review groups, or equivalent stakeholder forum) during the MTEP planning process pursuant to the Order 890 process detailed *in Attachment FF of the Tariff*;
- The updated cost estimate provided at Milestone 2 for the project has increased by twenty-five (25%) percent or more of the projected costs estimate provided at Milestone 1, where Milestone 1 occurs at the third Subregional Planning Meeting within an MTEP cycle (typically in mid-June) and Milestone 2 is the last quarterly project status update prior to the time the MISO Board is scheduled to meet to consider approval of the MTEP (typically end of September for a December Board approval).

MISO will produce a listing of any projects meeting this cost increase threshold and post it to the MISO website (including a notification to the Planning Advisory Committee) and provide it to the OMS Committee within seven (7) Days of receipt of the quarterly status update.

Should the OMS Committee exercise the option to recommend reconsideration of a project, such request must be forwarded to the MISO Staff, along with an explanation as to why such reconsideration request is being made, within no more than twenty (20) Days of the posting of the Milestone 2 costs and the provision of such cost information to the OMS Committee, where such posting will be made within seven (7) Days of receipt of the last quarterly project status update prior to the scheduled meeting of the System Planning Committee of the Board where consideration will be given to approving the MTEP. MISO staff will review the request and verify that at least one of the two conditions described above for invoking the project reconsideration request is valid. MISO staff will forward the OMS Request along with a good faith attempt to provide a substantive and meaningful response to the OMS Committee, the Planning Advisory Committee, and the System Planning Committee of the Board at least fourteen (14) Days prior to the System Planning Committee meeting to consider approval of the MTEP. MISO will re-convene the Planning Advisory Committee either in person or via conference call to provide an opportunity for the Planning Advisory Committee to make comments on the OMS Request prior to distributing the final MTEP recommendations to the System Planning Committee of the Board. The project reconsideration timeline is illustrated *in Figure 2.8.2.5-1 below*.

Figure 2.8.2.5-1: OMS Committee Project Reconsideration Request Timeline



3 Model Development

3.1 Introduction

MISO develops regional planning models which are used by MISO and its members for performing reliability and economic planning studies needed to fulfill various NERC and Tariff compliance obligations. This section describes MISO power flow model development processes through the Model On Demand (MOD) tool as applicable to the various planning functions discussed *in this BPM*.

3.2 Base Model Development for Planning Studies

The planning functions described below will provide input to the planning model development process through MOD. These planning functions will also specify criteria to output planning models from the MOD as needed to perform the specific planning studies.

- Base Models (PSS®E) for MTEP Reliability Analyses
- Base Models (PSS®E) for MTEP Economic Studies (Additional post processing outside MOD will be needed to prepare PROMOD economic models)
- Base Models (PSS®E) for Generator Interconnection Studies
- Base Models (PSS®E) for Transmission Service Request Studies
- Base Models (PSS®E) for other Non-cyclical planning studies

3.2.1 Model Development Timeline, Key Milestones, and Responsibilities

Figure 3.2.1.4-1 below, shows a general overview of the Planning Model Building Development process through MOD. The key process steps are explained below. Table 3.2.1.4-1 below, identifies the planning model development timeline, key milestones, and responsibilities. A detailed schedule for MTEP model development is posted on MISO website at Model Development Schedule.

3.2.1.1 Initiate Base Model Development for the Next Planning Cycle

MISO planning staff in consultation with Planning Subcommittee and Planning Advisory Committee determines the planning study years and seasons for which the base models need to be developed for the next planning cycle. Factors taken into consideration in determining the base model years/seasons include, study horizon used for the previous planning cycle, model years/seasons considered by NERC series models and neighboring coordinated systems, NERC standard compliance requirements, and other specific planning study requirements.

MISO will then request Transmission Owner(s) and other stakeholders to submit model updates in order to build base models for the next planning cycle.

3.2.1.2 Update Models

Before the beginning of the next planning cycle Transmission Owner(s) submit MOD project files to MOD for new reliability projects. Also, Transmission Owner(s) review Appendix A and Appendix B projects model data that are already in MOD from the previous planning cycle and submit corrections and modifications as necessary to the MOD. MISO planning staff will verify these MOD data submittals to make sure that model data match with project and facilities details in Transmission Projects database. Transmission Owner(s) also make any changes or corrections to equipment ratings through the MOD data submittal process.

As described *in Subsection 2.6.3 of MISO Model Data Requirements and Reporting Procedures and in Section 2.6 of this BPM*, Generator Owners (GO) are responsible for submitting modeling data for their existing and future generating facilities with a signed interconnection agreement, Load Serving Entities (LSE) are responsible for providing their scenario Load Forecasts, and TO are responsible for submitting data for their existing and approved transmission facilities.

GO are to coordinate with their interconnected TO in order to ensure that their data is consistent with the TO submitted topology. *In alignment with MISO BPM-011 – Resource Adequacy*, each LSE is responsible to work with applicable Electric Distribution Companies (EDC) to coordinate the submission of EDC forecast data in areas that have demand and energy that are subject to retail choice. LSE are expected to submit substation Load Forecasts directly to MOD/MISO unless they have made arrangements with their interconnected Transmission Owner to submit data on their behalf. If arrangements have been made, it must be communicated in writing to MISO.

As a best practice, it is desired that TO would also submit modeling data at their disposal for unregistered entities in their footprint. There is no obligation to do so and additionally no compliance repercussions relating to the data provided.

MISO planning staff shall work with Local Balancing Authorities to make changes to transaction and area interchanges based on the transaction data from OASIS and new information available through TSR Study process.

External system in MOD is updated based on the latest NERC series models and also based on any updates available from neighboring coordinated systems.

3.2.1.3 Preliminary Base Model Review

Once the data submittal process is complete, MISO planning staff creates preliminary base models based on the specific model requirements for different planning functions and horizons for stakeholder review. These preliminary models are posted to the MISO Planning Portal and Models ftp site. See the following location for information on accessing secure model sites: Client Relations. The schedule for review and feedback is posted along with the models and typically has the timelines *shown in Table 3.2.1.4-1 below*.

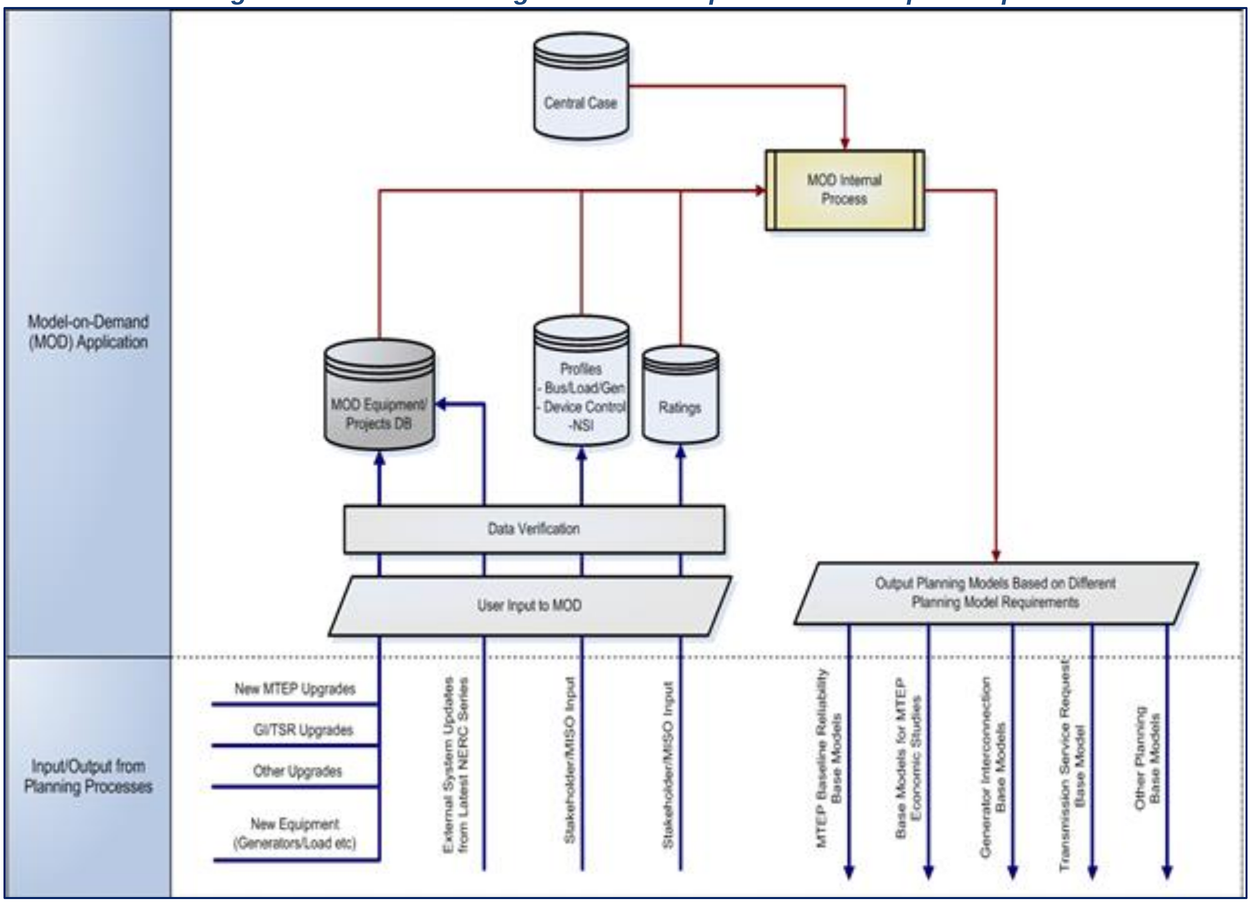
3.2.1.4 Develop Base Models for Planning Studies

Any additional model updates and corrections needed are submitted through MOD by the appropriate data submitters described above. MISO planning staff then posts the Base Models for different planning functions on the ftp site.

Table 3.2.1.4-1: Model Development Timeline, Key Milestones, and Responsibilities (Occurs between August and March of each Year on Schedule provided by MISO)

Activity	Responsibility
(A) Initiate base model development for the next planning cycle	
Determine base model study years and seasons for the next planning cycle	MISO planning staff, SPM/PS/PAC
Solicit model update input	MISO staff
(B) Update models	
Submit project files/idevs for new projects	Transmission Owner(s)
Review existing projects in MOD (processed during previous planning cycle) and submit corrections and modifications as necessary	Transmission Owner(s)
Submit equipment rating updates and other model corrections	Transmission Owner(s)
Submit Transmission Owner collected/projected Load Forecast data to MOD on a substation basis	Transmission Owner(s)
Collect Load Forecast data from LSEs/Network Customers – MOD Load Forecast information is compared with Load Forecast data collected from LSEs/Network Customers at the beginning of the planning cycle	MISO planning staff, LSEs
Submit new generator information, unit retirement information (through SSR study process), and generator profile changes to MOD	MISO planning staff, Transmission Owner(s)
Update Transaction data based on information from OASIS and TSR Study process	MISO planning staff
Update the external system from the latest NERC series update and/or updates available from neighboring coordinated systems	MISO planning staff
(C) Preliminary Base Model Review	
Output preliminary base models based on the specific model requirements for different planning functions	MISO planning staff
Post models for review on the MISO Planning/Models ftp site	MISO planning staff
stakeholder review of preliminary models	stakeholders
(D) Develop Base Models for Planning Studies	
Submit additional model updates corrections through MOD based on model review feedback	MISO planning staff, Transmission Owner(s)
Post revised base models on the ftp site	MISO planning staff

Figure 3.2.1.4-1: Planning Model Development - MOD Input/Output



3.2.1.5 Base Models for MTEP Reliability Analyses

MOD will be used to create the starting models to assess near-term (years one through five) and long-term (years six through ten) planning horizons.

3.2.1.5.1 Study Horizon

In general, at the beginning of each planning cycle, the following models will be developed to simulate two year out, five year out and ten year out conditions:

- Two year out summer peak case
- Five year out summer peak case
- Five year out off-peak case
- Ten year out summer peak case

Other study year models may also be developed as necessary depending on specific system conditions that need to be evaluated as part of the planning process described *under Section 4 of this BPM*.

3.2.1.5.2 Model Requirements

Section 4.3.5 of this BPM describes the specific model requirement for MTEP reliability planning models. Unless otherwise specified *under Section 4.3.5 of this BPM*, the General System Model Criteria described *under Section 3.3 below* will be used.

3.2.1.5.3 Model Review

MISO planning staff will create the initial MTEP reliability planning models using MOD and post the starting models on the MISO Planning Portal (MTEP Portal) and MTEP ftp site for stakeholder review. Access to MTEP models requires executing the relevant non-disclosure agreements (NDA) and following the instructions posted on the MISO Access Our Models page, Client Relations.

The timetable for the MTEP model review and approval process will also be posted on the MTEP ftp site at the beginning of each planning cycle.

3.2.1.6 Base Models for MTEP Economic Studies

Based on the defined economic study scope, MOD will be used to create the starting power-flow models for the selected planning study years.

3.2.1.6.1 Study Horizon

Economic models will be developed to simulate five-year-out, ten-year-out and fifteen-year-out economic conditions using the five-year-out and ten-year-our summer peak powerflow cases.

3.2.1.6.2 Model Requirements

Transmission topology data for the economic models are based on the powerflow base models applicable to the chosen economic study year. The Load and generation information source is as described *in Section 4.4.3 of this BPM*. *See Section 4.4.3 of this BPM* for additional information on data Sources and assumptions used for economic studies.

3.2.1.6.3 Model Review

MISO planning staff will create the initial MTEP economic planning models using MOD and post the starting powerflow models on the MTEP ftp site for stakeholder review. Changes identified through the stakeholder review will be made prior to using the powerflow models for economic studies. The timetable for the MTEP model review and approval process will also be posted on the MTEP ftp site at the beginning of each planning cycle.

3.2.1.7 Base Models for Generator Interconnection Studies

See Appendices E, F, and G for details on GI study functions and model requirements. Unless otherwise noted in those Appendices, the General System Model Criteria described *under Section 3.3 below* will be used.

3.2.1.8 Base Models for Transmission Service Request Studies

Section 5.0 of this BPM describes the specific model requirement for TSR study models. Unless otherwise specified *under Section 3.3 of this BPM*, the General System Model Criteria described *under Section 3.3 below*, will be used.

3.2.1.9 Base Models for Other Non-cyclical Planning Studies

Section 7.0 of this BPM describes the specific model requirement for other non-cyclical planning studies. Unless otherwise specified *under Section 7 of this BPM*, the General System Model Criteria described *under Section 3.3 below,* will be used.

3.3 General System Model Criteria

3.3.1 Topology Modeling

Topology of the MISO system will reflect the updates from the MISO Transmission Plan, which includes Baseline Reliability and Market Efficiency Projects, and New Transmission Access

Projects. Project status will be reviewed by the MISO planning staff in consultation with the stakeholders before making a determination on including specific future transmission system upgrades in different planning models. Neighboring systems will also be updated based on the data available through the information exchange and coordination arrangement with the neighboring RTOs and regions. The rest of the external system will be updated based on the latest NERC series model information.

3.3.2 Load Modeling

Load will generally be modeled as the most probable (50/50) coincident Load projection for each Transmission Owner service territory, for the study horizon under study. The Load Serving Entity shall provide MISO with Load Forecasts that are comparable with the Load Forecasts data submitted to MISO via the by LSE in other processes. However, there are times when the forecasts may not be identical based on factors such as the treatment of station service Loads. Coincident Loads of each Local Balancing Authority are reflected in the base models for the MISO reliability footprint. The external area Load is modeled as represented in the NERC series models or the neighboring coordinated system used to develop the MOD base models. Conforming and non-conforming Loads need to be differentiated when submitting Load data through MOD. Controllable demand-side management (interruptible Load that can be curtailed, during emergency conditions only) and uncontrollable demand-side management (peak shaving) are identified when submitting Load data to the MOD. Remote Loads (Loads that belong to a company but physically located in another control area) are identified in the inter-area transaction lists submitted through the MOD for proper accounting and modeling. Please refer to the MOD-032 Model Data and reporting Procedures document for more information on submitting Load data for appropriate Load modeling.

3.3.3 Generator Modeling

All existing generators are modeled and the generators that are not part of the Network Resources are modeled off-line unless required to meet public policy, such as renewable energy standards. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on their start date, based on the information provided by the Generator Owners through the System Support Resource study process. Units with approved Attachment Y Notices that have waived their interconnection rights (i.e., retired) will remain offline indefinitely. Units with approved Attachment Y Notices that have not waived their interconnection rights (i.e., suspended) will remain offline for the first 3 years following their start date and after the 3 years they will be available for dispatch. Future generators with a signed Interconnection Agreement are also modeled based on the information available through MISO Generator Interconnection process. If additional generation is needed to serve future Load growth, especially in the case of longer-term models, market resources will be dispatched as available, then proxy generation is modeled based on information available from the interconnection queue and/or through the future generator siting process explained *in Section 4.4 of this BPM*. Such proxy generation used in the model are separately identified and documented.

Jointly Owned Units (JOUs) or shared resources are represented in the models either as inter-area transactions or multiple units connected via zero-impedance lines. MISO planning staff will coordinate the appropriate modeling of the JOUs with the respective data submitters for these units. MISO will model resource auction units purchases outside MISO in a similar fashion.

3.3.4 Transactions/Interchanges

The interchanges modeled are derived from the transactions modeled in the latest NERC series models and as updated by Local Balancing Authorities, Transmission Owner(s), and MISO planning staff to reflect new transaction information from OASIS and/or MISO Transmission Service Request study process.

3.3.5 Representation of Lower Voltage Level

The power system models must contain the Bulk Electric System (BES) as typically modeled in NERC series models and required for NERC transmission planning standard compliance. Any sub-BES, lower-voltage transmission may also be modeled as needed to provide additional transmission detail and perform the planning functions described elsewhere in this BPM.

3.3.6 Facilities Ratings in Planning Models

Planning models will be populated with applicable ratings for system intact and contingent conditions. These ratings are developed per FAC-008 and submitted to Model On Demand (MOD) tool for existing and future facilities. Normal ratings are the applicable ratings for system intact conditions and emergency ratings are the applicable ratings for contingent conditions. When producing power flow models from MOD, Rate A will be populated with the normal rating from MOD and rate B will be populated with the emergency rating from MOD for the appropriate seasons.

4 Cyclical Planning Activities

Cyclical planning establishes the transmission expansions that are needed to address both short-term and long-term Transmission Issues that arise on an on-going basis. As such, cyclical planning encompasses a number of sub-processes that link to each other but that have their own associated procedures, schedules, and stakeholder interactions.

4.1 Stakeholder Interactions during Regional Planning Cycle

At each major step of the planning process, the MISO planning staff will engage stakeholders through the following planning groups and through various working groups, task forces and workshops that may be organized by these planning groups.

4.1.1 Subregional Planning Meetings

Subregional Planning Meetings (SPMs) are established under Attachment FF to the Tariff for the purpose of providing an interface to stakeholders on a more localized basis than the centralized stakeholder meetings of the Planning Subcommittee and the Planning Advisory Committee. SPMs are open stakeholder meetings subject to the CEII provisions under the Tariff and as described *in Section 2.7 of this BPM*. At a minimum, one SPM will be established for each of the four planning regions established under Attachment FF (North, Central, East and South). The SPMs will occur at the times and for the purposes listed *in Table 4.1.1-1 below* associated primarily with the bottom-up planning process described *in Section 4.3 of this BPM*.

Table 4.1.1-1: SPM Meetings Schedule

Purpose	Date	Location (Subject to change)
1. Provide additional input to MISO planning staff on stakeholder issues and needs. 2. Discuss pre-planning information and develop MTEP cycle study scope. 3. Review and provide input to planning models. 4. Review and discuss known issues proposed projects and solution ideas.	January	North, Central, East and South (locations to be announced)

Purpose	Date	Location (Subject to change)
1. Review system performance issue identified in initial phase analysis. 2. Discuss possible alternative solutions to issues.	March/April	North, Central, East and South (locations to be announced)
1. Review results of alternative analyses. 2. Comment on proposed preferred solutions.	June/July	North, Central, East and South (locations to be announced)

4.1.2 Planning Subcommittee

The Planning Subcommittee (PS) is also established under Attachment FF and operates under the stakeholder Governance Guides developed by the Committee Restructuring Group. The PS charter is posted on the MISO Planning website. In general, the PS is a stakeholder group of participants interested in MISO planning issues and processes. The PS meets at regular bi-Monthly meetings or as otherwise established under the charter. For the purposes of addressing review and comment on the MTEP regional plan development, the PS will meet at the times and for the purposes listed *in Table 4.1.1-2 below*, associated primarily with the short-term planning process described *in Section 4.3 of this BPM*.

Table 4.1.1-2: PS Meetings Schedule

Purpose	Date[7]	Location (Subject to change)
1. Review and comment on scope of analysis proposed by SPMs. 2. Review and Comments on models. 3. Other regular agenda items as developed by MISO planning staff or participants.	February	Location to be Announced
1. Review MTEP analysis results. 2. Discuss possible alternative solutions to issues. 3. Other regular agenda items as developed by MISO planning staff or participants.	April	Location to be Announced

[7] Reference Committee calendar for specific dates

Purpose	Date[7]	Location (Subject to change)
1. Review MTEP analysis results 2. Other regular agenda items as developed by MISO planning staff or participants.	June	Location to be Announced
1. Comment on proposed preferred solutions. 2. Review preliminary Cost Allocations. 3. Other regular agenda items as developed by MISO planning staff or participants.	August	Location to be Announced
1. Comment on MTEP Report Draft. 2. Other regular agenda items as developed by MISO planning staff or participants.	September	Location to be Announced
1. Input on completed MTEP process. 2. Other regular agenda items as developed by MISO planning staff or participants.	October	Location to be Announced
1. Input on issues and scope for next MTEP. 2. Other regular agenda items as developed by MISO planning staff or participants.	December	Location to be Announced

4.1.3 Planning Advisory Committee

The Planning Advisory Committee (PAC) is established under the Transmission Owner(s) Agreement and Attachment FF and operates under the stakeholder Governance Guides developed by the Committee Restructuring Group. The Planning Advisory Committee is a source of input to the MISO planning staff toward development of the MTEP. Its membership consists of one Member from each of the following stakeholder groups:

- Transmission Owner(s)
- Municipal and cooperative electric utilities and transmission-dependent utilities
- Independent power producers and exempt wholesale generators
- Power marketers and brokers
- Eligible end-use customers
- State regulatory authorities
- Representative of public consumer groups
- Environmental and other stakeholder groups
- Transmission Developers
- Coordinator Sector

The PAC charter is posted on the MISO Planning website. In general, the PAC is a stakeholder group of participants interested in MISO policy issues as they relate to planning. The PAC meets quarterly, or as otherwise established under the charter. The PAC will review the MTEP scope of work developed through the SPM and PS meetings, and will provide input into the development of the assumption sets to be applied in the Long-term planning process. These assumptions include those related to development of planning Futures, Generation Resource forecasts and siting, and transmission plan development. Agenda items to address these issues will be established annually by the PAC in collaboration with MISO planning staff. MISO planning staff will also organize various stakeholder workshops to address long-term planning issues and process.

The PAC provides a final review of each MTEP report and provides its advice to the MISO planning staff, the Advisory Committee, and the Transmission Provider Board.

4.1.4 Expedited Project Review

In accordance with Attachment FF to the tariff, in the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project, MISO shall use a streamlined approval process for reviewing and approving projects proposed by the Transmission Owner(s) so that decisions will be provided to the Transmission Owner within thirty (30) Days of the project's submittal to MISO unless a longer review period is mutually agreed upon.

4.1.4.1 Notification of Need for Expedited Review

When it becomes necessary for a Transmission Owner to request expedited project review, the Transmission Owner will submit the project and corresponding data to MISO using a request form posted on the MISO website: Expedited Project Review Request. Valid requests must include all of the supporting information indicated on the form. MISO will post valid requests within two weeks after receipt.

4.1.4.2 Expedited Review Process

MISO will integrate the expedited review of the project into the Subregional Planning Meetings (SPM) and/or Technical Studies Task Force (TSTF) meetings of the current MTEP cycle. MISO will review the project with stakeholders for impacts on system reliability performance in the same manner as for all other local area projects rolled-up into the current MTEP cycle review. Such reviews include consideration of planning criteria, planning analysis, models, Load Forecasts, and alternatives consistent with the planning process provisions of Attachment FF to the tariff in order to ensure the project does not adversely impact reliability and/or any Baseline Reliability Project, that the project adequately addresses the reliability deficiency.

As with all projects reviewed in the annual cycle, any project undergoing expedited review that would otherwise qualify for regional cost sharing as a Market Efficiency Project (MEP), based upon project cost and voltage threshold criteria, and that would be eligible for competitive development, will be evaluated to see if it would qualify as an MEP except for the urgent need (established by the Transmission Owner). This assessment will be provided for informational purposes if the lead-time and the required in-service date of the project preclude its treatment as an MEP.

4.1.4.3 Inclusion of Project in MTEP

Based upon the completed project review, including input from stakeholders at the SPM/TSTF meeting, MISO will make a determination as to inclusion of the project, or preferred alternative, in the Appendix A of the current MTEP. Once included in the Appendix A it is expected that the Transmission Owner will proceed to implement the project in order to meet its obligations and requirements as provided for in the Transmission Owner's Agreement. The project will be included in the Appendix A list of projects to be presented to the Board of Directors for Certification at the completion of the current annual MTEP cycle. MISO will identify the projects in the MTEP report that have been reviewed on an expedited basis, and will include a report on the number of Expedited Review requests by Transmission Owner.

The results of the completed expedited project review at the SPM/TSTF will be presented at the next available Planning Advisory Committee (PAC) meeting at which the meeting material posting requirements of the stakeholder Governance Guide can be adhered to. Written comments from the PAC on any Expedited Review Projects will be included with other PAC comments on the MTEP at the completion of the annual MTEP cycle. MISO staff will consider the input from the PAC when applying its discretion to determine whether or not to raise the recommendation of the project for inclusion in MTEP to the attention of the System Planning Committee (SPC) of the MISO Board. Stakeholders may also provide advice relative to the project to the SPC and/or the Board in accordance with the protocols of the Advisory Committee.

4.1.4.4 Projects Not Eligible for Expedited Review

Projects that meet tariff criteria to be included in MTEP as an MEP, or that otherwise provide for market efficiency or other needs, and that are not needed to meet the obligations or requirements of the Transmission Owner will not be reviewed on an expedited basis.

4.1.4.5 Expectations of Transmission Owner(s)

The open and transparent planning requirements of Attachment FF to the tariff require that no proposed project of a Transmission Owner that has elected to integrate their local planning processes into the Transmission Provider's processes shall be recommended in the MTEP for implementation until completion of the annual needs analysis carried out in the annual MTEP cycle, except when an expedited review is necessary. Expedited review requests should be exceptions to the normal review process. It is expected that the Transmission Owner will identify the need for projects early enough to be fully vetted in the annual MTEP cycle without the need for expedited review. The Transmission Owner will be expected to present to stakeholders and to MISO at the SPM/TSTF review the reasons why the needs driving the project are urgent and why the project was not identified early enough to be reviewed in the full MTEP review cycle.

4.2 Pre-planning Steps Common to Bottom-up and Top-down Planning

Each MTEP regional planning cycle commences with the assembling of initial information from stakeholders and Transmission Owner(s), and system performance data. This information is used to finalize a scope of work for the current planning cycle. The annual scope of work is generally expected to be consistent from cycle to cycle but may involve alternative analysis as may be dictated by the information received.

Initial information includes the reporting of data essential for development of system models, the process for which is described *in Section 3 of this BPM*.

4.2.1 Assemble Pre-planning Information

The MISO planning staff will collect and assemble information from both internal and external sources that may include but is not limited to:

- Transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests.
- Transmission needs associated with generator interconnection service.
- Transmission needs identified from prior completed short or long-term regional planning processes (i.e., prior MTEP).
- System performance information such as historical incidence of flowgate congestion data, TLR, AFC, any newly identified NCAs, impacts of recently retired generating units or plans for such that have been evaluated in SSR studies.
- Load Forecast and external system information received from the model building process and from Transmission Customers via tariff reporting requirements.
- Transmission needs identified by the Transmission Owner(s) in connection with their local planning analyses.

The first four items listed above are developed by MISO planning staff from internal information. Load Forecast and other modeling data is assembled in the model building process. The reporting and integration of needs identified by the Transmission Owner(s) in their local planning processes are described below.

4.2.2 Integration of Transmission Owner Local Planning Process

The regional planning process must have knowledge of and consider the locally developed plans of all Transmission Owner(s) at the front-end of the regional planning process in order to be able to develop a regional plan in an orderly manner. MISO planning staff solicits this information from Transmission Owner(s) at the front end of the annual planning cycle through a project reporting procedure. The local plans of Transmission Owner(s) are developed through various means, but generally include the following basic steps:

- Solicit input from larger local customers
- Analyze historical distribution Load and trends
- Develop local models
- Apply local planning criteria
- Identify local planning needs, issues, and potential solutions

When the Transmission Owner has developed local planning solutions, those solutions are submitted to the MISO planning staff. This project data is submitted in two (2) forms:

- To Model On Demand for model level data (e.g., script files or idevs that model the project, etc.).
- To the Project Database for descriptions of needs, solutions, alternatives and other project specific data.

This information is solicited by MISO planning staff shortly following the end of the most recently completed MTEP process, and just before the beginning of the next cycle. MISO planning staff assembles this local project information along with the other information described earlier for consideration and review through the MTEP regional planning process at the SPM level. These local planning considerations are assessed and evaluated through the open stakeholder process at SPM forums and integrated into the MTEP regional plan as described further below. For Transmission Owner(s) that have elected under Attachment FF to fully integrate their local planning process with the regional planning processes, the plans developed through local planning processes are included in the beginning of each regional planning cycle as potential alternatives to local system needs identified by the Transmission Owner(s). The regional planning process evaluates, with stakeholder input throughout the cycle, the local plans of these Transmission Owner(s), as one input into the development of the regional plan.

4.2.3 Project Reporting Guidelines

Members who are Transmission Owner(s) are required to report projects developed in their local planning processes and that have an expected in-service date within the MTEP planning horizon. Projects with in-service dates beyond the MTEP planning horizon and up to 10 years from the current year may be submitted for MISO review and tentative inclusion in the MTEP. All transmission voltage Projects with the following criteria must be reported to the Project Database:

- All projects that represent a system topology change (i.e., constructing a new circuit, tapping an existing circuit, removing a circuit from the planning model, or retiring a circuit). All projects that include interconnecting new distribution service from new or existing transmission facilities must report distribution sub taps.
- All new circuit breaker additions to transmission facilities.
- All upgraded circuit breakers that result in changes to a breaker’s continuous current-carrying or interrupting capacity.
- All projects that change the electrical characteristics of a circuit (i.e., changes to shunt or series inductors, capacitors, conductor type or performance, switches, current transformers, or wave traps).

- All projects involving like-for-like replacements with direct costs of $1 million or more.
- All projects that change a circuit rating.
- Generator interconnection projects with signed Interconnection Agreements (provided by MISO planning staff) and Network Upgrades associated with conditionally confirmed transmission service requests (TDSP).
- Existing interconnections of transmission facilities or electricity end-user facilities seeking to make a qualified change on the transmission system needs to report the qualified change to the project database. The qualified change is defined as: i) transmission system topology change; ii) protection configuration change that could negatively impact contingency performance, short circuit, or dynamic performance; iii) change the electrical characteristics of a circuit (i.e., change of impedance, current transformers) that could negatively impact contingency performance, short circuit, or dynamic performance.
- Members are encouraged (but are not required) to report projects that consist of like-for-like replacements costing less than $1 million, or projects that improve Transmission System operational performance such as SCADA systems, communications, or relaying upgrades.

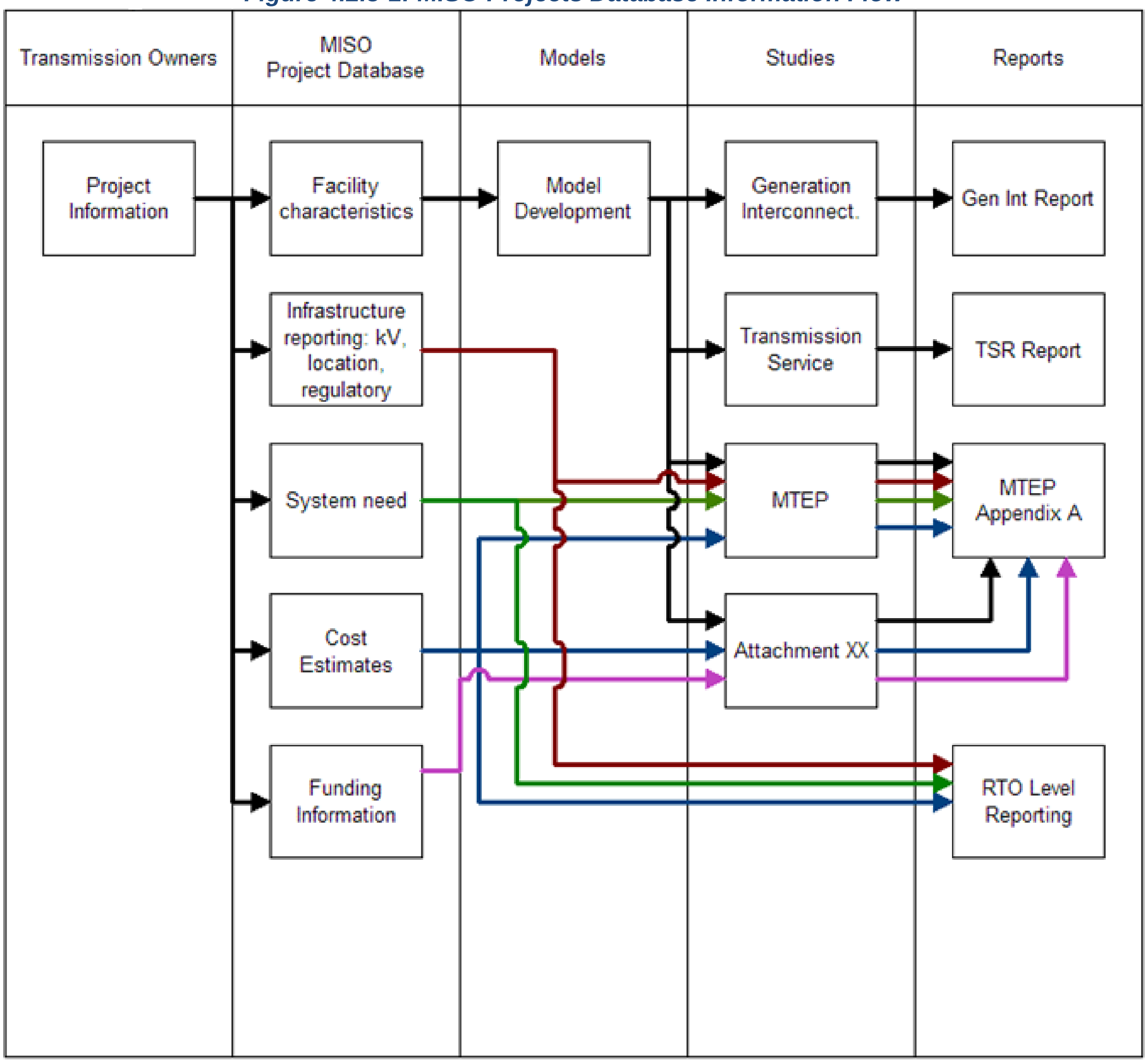
Project reports are submitted to MISO as part of the MTEP development and update cycle in December, prior to the start of each MTEP regional planning cycle. Project Database updates are reported to the designated MISO planning staff MTEP Appendix A Coordinator. Transmission Owner(s) that have their own FERC approved local planning processes may submit new project proposals and request MISO expedited review and endorsement during other Months within an MTEP cycle as provided for in the Transmission Owner(s) agreement. Other Transmission Owner(s) may only do so on an exception basis due to urgent need to begin development of a local project ahead of the normal regional planning cycle schedule. These expedited reviews are handled via the “Expedited Project Review” procedure described elsewhere in this BPM.

Project data is presently submitted to the Project Database using the MISO Planning Portal web application. The Project and Facility table field definitions are documented in the Planning Portal. Modeling data associated with these projects should also be submitted to the Model On Demand database.

To prepare and submit a required report, the Transmission Owner identifies projects that are planned or under development. Each project is associated with one or more facilities, and this relationship is specified in the Facilities table. The Project table includes a summary of modeling analysis results that support the reliability or economic improvement justification for each project.

Detailed analytical results supporting projects is kept in the study Results Database. Project information flow from the Transmission Owner(s) through the MISO planning process and into applicable reports is shown *in Figure 4.2.3-1 below*.

Figure 4.2.3-1: MISO Projects Database Information Flow



4.2.3.1 Project Status Updates

In accordance with the MISO Tariff[8], status updates are required to track the progress of a planned transmission project[9]. MISO will request status updates on a quarterly basis via an e-mail sent to the MISO Planning Superlist (which contains the PAC, PSC, and RECBWG lists) no later than fifteen (15) Calendar Days prior to the end of each calendar quarter. Quarterly status updates shall be submitted to MISO fifteen (15) Calendar Days after the end of each calendar quarter[10], except that the Quarterly status update shall be due on the last Calendar Day of the quarter for the quarter which Milestone 2 has been achieved. Such status updates shall be based on the best information available at the time, utilizing the status update template(s) provided by MISO in the respective email request.

In addition to quarterly status updates, MISO, at its sole discretion, may request additional status updates outside the quarterly update cycle. Upon such request, Selected Developers and Transmission Owners are required to provide MISO with the requested status update within ten (10) Business Days, or within a time period mutually agreed upon by MISO and the Selected Developer or Transmission Owner. In providing such status updates, each Selected Developer and Transmission Owner must make a good faith effort to provide MISO with the best information available at that time. MISO will check-in at least twice a year with each Transmission Owner on their project status for projects that were included in Appendix A of prior MTEP cycles.

4.2.3.1.1 Requirements for Eligible Project Facilities

Each quarterly status update for facilities identified in an Eligible Project[11] approved after December 1, 2015, shall contain, at a minimum, the information specified *in Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM*:

I. Development status[12] of each facility;
II. Estimated in-service date for each facility, including the identification of any changes;
III. Estimated cost to complete each facility[13];
IV. Estimated total project costs[14] and the identification of any changes from the Baseline Cost Estimate[15];

8 Attachment FF §I.C.11 of the Tariff
9 i.e. one that is either listed in MTEP Appendix A or is proposed by MISO staff to move to Appendix A in the current planning cycle
10 i.e. March 31, June 30, September 30, and December 31 of each year.
11 'Eligible Project' is defined by the MISO Tariff under Module A.1.E.
12 e.g. 'Proposed', 'Planned', 'Under Construction', 'In-Service', etc.
13 Specified in nominal US $'s representing the accumulated spend in year of occurrence dollars that will be recovered
14 Specified as the sum of each facility cost-estimate provided under Section 4.2.3.1.1.IV of this BPM
15 'Baseline Cost Estimate' is defined by the MISO Tariff in Section IX.C.1.1 of Attachment FF

V. Identification and description of items included in the reported estimated total project cost *under Section 4.2.3.1.1.V of this BPM*, such as allowance for funds used during construction ("AFUDC"), construction work in progress ("CWIP"), overhead, contingencies, etc.;
VI. Project expenditures as of the end of the previous calendar quarter[16];
VII. The percentage of the project expenditures provided *under Section 4.2.3.1.1.VII of this BPM* versus the Baseline Cost Estimate[15] (e.g. expenditures / Baseline Cost Estimate);
VIII. Project schedule depicting the activities for each facility, including the identification of any changes[17];
IX. Design and engineering status[18] for each facility;
X. Status of obtaining necessary regulatory and or environmental permits, certificates, or approvals, including meeting necessary licensing requirements, for each facility;
XI. Status of any necessary land and right-of-way acquisition for each facility[17];
XII. Status of any necessary interconnection agreements for each facility[17];
XIII. Construction status for each facility;
XIV. As applicable, detailed cost estimates for each transmission line facility as follows:
    a. Engineering labor per transmission line facility[13];
    b. Construction labor per transmission line facility[13];
    c. Right-of-way acquisition per transmission line facility[13];
    d. Material procurement per transmission line facility[13]; and
    e. Regulatory or miscellaneous costs per transmission line facility[13].
XV. As applicable, detailed cost estimates for each substation facility as follows:
    a. Engineering labor per substation facility[13];
    b. Construction labor per substation facility[13];
    c. Land acquisition/site property rights per substation facility[13];
    d. Material procurement per substation facility[13]; and
    e. Regulatory or miscellaneous costs for each substation facility[13].

Each quarterly status update indicating a material change or deviation from the MTEP in-service date, Baseline Cost Estimates, or any information submitted in previous status updates, shall also include: an explanation of such change; the cause of, or the reason for, such change; and an assessment of the impact such change may have on the project, including the continued ability to meet the MTEP in-service date and any plans to mitigate such impacts.

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16 Specified in US $'s as the sum of each facility's expenditures
17 May be submitted as one (1) or more attachments to the status update
18 e.g. 'Not-Started', 'Started', 'Completed', etc.

In addition to the information required to be included in the quarterly status updates *under Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM*, the information specified *in Sections 4.2.3.1.1.XVII through 4.2.3.1.1.XX of this BPM* are also required to be submitted to MISO within one hundred and eighty (180) Calendar Days[19] of the date the facilities are energized.

XVI. Final costs to construct the facilities[13];

XVII. Final 'as-built' drawings[20] for each facility;

XVIII. Inspection reports[20] for each facility, if any inspections were performed; and

XIX. Geo-spatial information[20] for each facility (e.g., GIS maps, GPS coordinates, etc.).

4.2.3.1.2 Requirements for Competitive Transmission Facilities

Each quarterly status update for the Competitive Transmission Facilities identified in an Eligible Project shall contain, at a minimum, the information specified *in Sections 4.2.3.1.1.I through 4.2.3.1.1.XVI of this BPM* and the additional information specified *in Sections 4.2.3.1.2.I through 4.2.3.1.2.VI of this BPM*:

I. Status of any necessary project financing;

II. The percentage (%) of the total expenditures to date versus the total projected cost schedule provided in the Selected Proposal[21];

III. Whether any rate filings associated with the Competitive Transmission Facilities were made during the previous calendar quarter or are expected to be made during the upcoming calendar quarter;

IV. Disclosure of any changes in the continuing ability of the Selected Developer to meet its obligations under the Selected Developer Agreement, according to the schedules and milestones agreed to therein, including any binding cost caps or cost containment measures that were included in the Selected Proposal;

V. Identification of and an explanation of any changes from the specifications included in the Selected Proposal; and

VI. If any changes are identified in a quarterly status update *under Section 4.2.3.1.3.V of this BPM*, the quarterly status update shall include the Selected Developer's assessment of any impacts on the Competitive Transmission Facilities resulting from such changes.

In addition to the information required to be included in the quarterly status updates *under Sections 4.2.3.1.2.I through 4.2.3.1.2.VI of this BPM*, the information specified *in Sections*

[19] This may be submitted on a different day if both MISO and the Transmission Owner or Selected Developer agrees on a different date.

[20] Submitted as one (1) or more attachments to the status update

[21] Specified as the sum of expenditures to date of each Competitive Transmission Facility of the Competitive Transmission Project in US $.

4.2.3.1.1.XVII through 4.2.3.1.1.XX of this BPM are also required to be submitted to MISO within one hundred and eighty (180) Calendar Days[22] of the date the facilities are energized.

4.2.3.1.3 Milestones

Transmission Owners are encouraged to provide updates as frequently as possible, especially after a project's schedule or estimated costs shift by a significant amount. Projects that have not reached or passed a milestone in the last quarter are not required to submit project status updates, although the Transmission Owners must confirm that they have received the request and have no projects that have reached or passed a milestone. Project status updates are required for any projects which have reached and/or passed one of the milestones listed below. If no milestone is reached during the calendar year, then a project status update is required at the end of the year. Transmission Owners must make good faith efforts to provide the best information available concurrent with Milestone 1, 2, 3, and 4 for the quarter immediately following the achievement of Milestone 5.

There are six (6) milestones that shall be utilized in status updates, they are:

- Milestone 1 - Final Subregional Planning Meeting / Expedited Review Submittal;
- Milestone 2 - Pre-project approval;
- Milestone 3 - Long lead materials;
- Milestone 4 - Pre-construction; and
- Milestone 5 - Facility completion.

For typical projects, excluding projects submitted for Expedited Review, Milestone 1 corresponds to the final Subregional Planning Meeting in which a particular project is discussed prior to it being submitted to the MISO Board of Directors for their consideration (typically in June prior to a December approval). For projects submitted for Expedited Review, Milestone 1 will occur at the submission of the Expedited Review request form. The Milestone 1 status update for transmission projects that are to proceed through the MISO Competitive Developer Selection Process will be provided by MISO. For all other transmission projects, the responsible Transmission Owner(s) will provide the status updates.

For all typical (i.e., not projects submitted for Expedited Review) projects, Milestone 2 corresponds to the last quarterly status update prior to the time the MISO Board of Directors is scheduled to meet to consider approval of the project (typically September for a December approval). For all projects submitted for expedited review, Milestone 2 will occur at the Planning

[22] This may be submitted on a different day if both MISO and the Transmission Owner or Selected Developer agrees on a different date.

Advisory Committee meeting where the project is discussed. For transmission projects that may meet one or more regional cost sharing criterion, MISO will provide the status update for Milestone 2. For all other transmission projects, the assigned Transmission Owner(s) will provide the status update for Milestone 2.

For all projects, Milestone 3 corresponds to the quarter prior to when the Transmission Owner or Selected Developer will place their first order for materials and equipment requiring a long lead time (i.e., materials which require at least 6 Months between their order and receipt).

For all projects, Milestone 4 corresponds to the quarter prior to commencement of physical construction on the facilities associated with the transmission project.

It is recognized that the timing of reporting updates for Milestones 3 and 4 may be significantly in advance of the availability of the most accurate information. For example, ordering of equipment or construction commencement may be scheduled for the end of the next quarter which would necessitate providing an update as much as six (6) Months in advance of that activity. As such, Transmission Owners and Selected Developers are expected to make good faith efforts to provide updated information prior to reaching the Milestones. The Transmission Owner and Selected Developer may provide updated information at the next quarterly request if more accurate information is available. If the Transmission Owners and Selected Developers are unable, due to changes in the expected project schedule, to make this update prior to the Milestones they must provide the information at the next quarterly request.

For all projects, Milestone 5 corresponds to the point when a project is complete, and all capital expenditures for its design, engineering, and construction have occurred.

4.2.3.1.4 Requirements for All Other Transmission Facilities

Transmission Owners must provide status updates for all transmission facilities that were not included in either an Eligible Project, *in accordance with Section 4.2.3.1.1 of this BPM*, or a Competitive Transmission Project, *in accordance with Section 4.2.3.1.2 of this BPM*, for which they are responsible. These updates must contain, at a minimum, the following data:

I. Most Recent Milestone Achieved;
II. In-service Date;
III. Planning Status (Proposed, Planned, Under Construction, In-Service); and
IV. Total Project Cost Estimate

Additional information is required in status updates for all transmission facilities that meet one or more of the following criteria specified *in Sections 4.2.3.1.4.V through 4.2.3.1.4.VII of this BPM*:

V. Estimated facility cost is $50 million or greater;
VI. Transmission facility is regionally cost shared (i.e., has any costs allocated outside of the local pricing zone where the facility is geographically located) within the MISO footprint; or
VII. Transmission facility is cost shared with entities beyond the MISO footprint.

For transmission projects that meet one or more of the criteria listed above *in Sections 4.2.3.1.4.V through 4.2.3.1.4.VII of this BPM*, the status updates must include the additional information specified *in Sections 4.2.3.1.4.VIII through 4.2.3.1.4.XII of this BPM*:

VIII. Detailed cost estimates** for each line, broken down as follows:
  a. Engineering labor per facility*
  b. Construction labor per facility
  c. Right-of-way per facility
  d. Material per facility
IX. Detailed cost estimates** for each substation, broken down as follows:
  a. Engineering labor per facility
  b. Construction labor per facility
  c. Site property rights per facility
  d. Material per facility
X. Any regulatory or miscellaneous costs**
XI. Project expenditures to date**
XII. Comments describing current variances

* In this context, a project is a transmission upgrade identified in the MISO planning process and included in the MISO Transmission Expansion Plan (MTEP). Facilities are subset of projects associated with a given project.

** Detailed cost information will not be made public but will be used only to provide information to internal MISO staff. State regulators shall receive information as provided for under the Tariff, pursuant to the appropriate nondisclosure and confidentiality agreements.

4.2.3.1.5 Use of Status Update Information

MISO will use the data provided in the status updates to create an aggregate status report on a quarterly basis, redacting any Confidential Information and Critical Energy Infrastructure Information (CEII) as necessary. Quarterly status reports for the previous calendar quarter will be publicly posted on the MISO website no later than thirty (30) Calendar Days after the respective calendar quarter (e.g., the status updates for the 1st quarter of a given year will be posted on or before April 30th of that year, thirty (30) Days after the 1st quarter ended) Unless required sooner. Posted status reports will not include CEII or Confidential Information; however, they will include, at a minimum, the following information for all projects:

I. Project development status, as reported in the status updates;
II. Original project in-service date, as indicated in the approved MTEP report;
III. Updated project in-service date, as reported in the status updates;
IV. Change in the in-service date from original in-service date (in Months);
V. Change in in-service date since last project status update (in Months);
VI. Original estimated total project cost, as indicated in the approved MTEP report;
VII. Updated estimated total project cost, as reported in the status updates;
VIII. Expenditures to date (in dollars and percent of total estimated project cost);
IX. Change in estimated total project cost since last status update (in percent);
X. Change in estimated total project cost since original estimate indicated in the approved MTEP report (in percent); and
XI. A summary of any comments.

Data provided in the status updates will also be used in presentations given to the MISO Board of Directors and stakeholders. In accordance with the MISO Tariff[23], a presentation will be given to the System Planning Committee of the Board of Directors on a quarterly basis, or as otherwise directed by the MISO Board of Directors. Further informational updates will be provided to the Planning Advisory Committee as specified by the Planning Advisory Committee management plan.

4.2.4 Study Scope Development

Once MISO planning staff assembles pre-planning information, a draft scope of study is prepared by the MISO planning staff and distributed to the SPMs, the PSC and the PAC. These stakeholder groups meet on the schedules described above to shape the scope of the current study cycle. In developing the scope of study, the stakeholders and MISO planning staff will consider all of the available pre-planning information as well as any particular service issues raised by stakeholders at these meetings. Stakeholders are invited to solicit written comments and information to help guide the planning analysis before and after stakeholder meetings. MISO Planning staff will endeavor to provide a written reply to all specific stakeholder recommendations for study that are not adopted.

[23] Attachment FF §I.C.11 of the Tariff

4.3 Bottom-up Planning

Bottom-up transmission expansion planning addresses identification of reliability and localized Transmission Issues and development of solutions in the time frame of one to ten years, with particular focus placed on the next five years. Bottom-up transmission expansion planning is the process used by MISO (the NERC Planning Coordinator or PC) and the Transmission Owner(s) (the NERC Transmission Planners or TP) to comply with NERC TPL standards in particular, and other NERC and regional standards applicable to MISO and/or the Transmission Owner(s) when compliance with such standards is achieved entirely or partially through the transmission expansion planning process. Bottom-up transmission expansion planning is also the process used by MISO and the Transmission Owner(s) to i) comply with state and local planning requirements; ii) comply with the Transmission Owner's own planning criteria; iii) and address requirements or needs related to local issues (e.g., requirement to relocate existing transmission facilities, etc.), operational and safety issues (e.g., the need to replace problematic equipment, etc.), infrastructure issues (e.g., the need to replace aging facilities, etc.), and reliability issues outside the scope of the NERC and regional standards (e.g., transmission upgrades to improve end-use customer service reliability, etc.).

As discussed in more detail *in Section 2.3 of this BPM*, bottom-up transmission planning produces projects classified as either Baseline Reliability Projects (if such projects are required to comply with NERC standards, particularly NERC TPL 001 standards) or "other" projects. Bottom-up transmission projects may be submitted by Transmission Owner(s) (acting in their role as Transmission Planners) for evaluation in the MISO transmission expansion planning process or may be developed directly within the MISO transmission expansion planning process based on ideas developed by MISO stakeholders and/or MISO staff.

4.3.1 Steps in the Bottom-Up Transmission Expansion Planning Process

Key Milestone points in the bottom-up transmission expansion planning process for a particular MTEP cycle are as follows:

- Development of the bottom-up expansion planning scope of work for the current MTEP
- Development of bottom-up planning models as discussed *in Section 3 of this BPM*
- Identification of projected issues with no system improvements
- Development of alternative solutions to identified issues
- Selection of the best solutions to address identified issues
- Testing the final solution set to ensure the plan is fully compliant with all applicable standards, criteria, and requirements.
- Monitoring progress of solution implementation

4.3.1.1 Identification of Projected Transmission Issues with No System Improvements

Once the MTEP scope has been finalized and the required models have been developed as further discussed *in Section 3 of this BPM*, simulations of the transmission system will be performed to identify projected violations of i) NERC TPL standards, ii) other NERC and regional standards, iii) state and local jurisdictional requirements, and iv) Transmission Owner planning criteria. Simulations will be performed in accordance with the NERC TPL standards, regional planning standards, and Transmission Owner planning criteria regarding the specific Loading conditions (e.g., summer peak, shoulder peak, light Load, etc.), time horizons (e.g., two-year out forecasted Loads, five-year out forecasted Loads, ten-year out forecasted Loads, etc.) and contingencies to be evaluated. Simulations will analyze, as stipulated in the NERC TPL standards and other applicable standards and planning criteria, i) steady-state performance (thermal loading and steady state voltages), ii) stability (voltage stability and transient angular stability), iii) susceptibility to cascading, and iv) performance during transient conditions (e.g., susceptibility to tripping during stable power swings, ability to ride through transient voltages, etc.).

The issues identification phase will tabulate all projected issues including the specific conditions and/or sensitivities that produced the issues and the specific standards or planning criteria that are violated.

4.3.1.2 Development of Alternative Solutions to Projected Issues

Once issues are identified, the planning process will explore alternative solutions to those issues with the objective of recommending the best overall solutions. Consistent with Attachment FF of the Tariff, both transmission and Non-Transmission Alternatives (NTA) to resolve Transmission Issues will be considered on a comparable basis within the MISO transmission planning process. Non-transmission alternatives include contracted demand response, new or upgraded generators with executed interconnection agreements, and other non-transmission assets (e.g., energy storage not classified as a transmission asset, etc.).

With regard to transmission alternatives, the Transmission Owners Agreement provides MISO with the authority to compel a Transmission Owner to make a good faith effort to construct transmission facilities included in Appendix A of an approved MTEP or, in the case of transmission facilities subject to competitive bidding, the Transmission Owners Agreement provides MISO with the authority to develop and issue RFPs for such transmission facilities. For non-transmission alternatives, the Transmission Owners Agreement and Tariff provide no such authority to MISO.

However, in order to provide for the consideration of both transmission and non-transmission alternatives within the overall transmission planning process in accordance with Order 890 and Order 1000, MISO will provide, upon request, information regarding the minimum requirements that must be satisfied for the entire planning horizon by non-transmission alternatives in order to address identified Transmission Issues, and to the extent that a non-transmission alternative or alternative is pursued in accordance with the requirements outlined in Attachment FF of the Tariff and this BPM, MISO working with the responsible Transmission Owner will defer, de-scope, or withdraw the transmission project previously proposed to address the Transmission Issue. This process facilitates MISO compliance with FERC Order 890 in a manner that is consistent with MISO’s authorities and responsibilities as outlined in the Tariff and the Transmission Owners Agreement.

With regard to non-transmission alternatives, in order to ensure comparability for such non-transmission alternatives, Attachment FF requires adherence to the following:

- For generation alternatives, a Generation Interconnection Agreement must be executed pursuant to Attachment X of the Tariff and in accordance with the requirements of Attachment FF.
- For demand response alternatives, a demand response agreement must be executed between the applicable LSE(s) and end-use customer(s) in accordance with the requirements of Attachment FF.

The scope of transmission alternatives that could address a Transmission Issue include: (i) operational intervention such as redispatch and/or reconfiguration of the transmission system through operator instruction (i.e., system adjustments); (ii) implementation of remedial action schemes subject to applicable standards and approvals; and/or (iii) transmission expansion such as the upgrade of existing facilities or the construction of new transmission facilities. The scope of non-transmission alternatives that could address a Transmission Issue include: (i) contracted demand response; (ii) planned generator interconnections with executed interconnection agreements; and/or (iii) mitigating impacts of any other planned non-transmission assets.

If a non-transmission alternative or alternative is pursued and it effectively addresses the applicable Transmission Issue(s) through the execution of applicable agreements within a time period where it is feasible to defer, de-scope, or withdraw a previously proposed transmission project, then the non-transmission alternative or alternative may result in the transmission project being deferred, de-scoped, or withdrawn as appropriate based on subsequent analyses by MISO and the responsible Transmission Owner(s) using models that incorporate the non-transmission alternative. To the extent no non-transmission alternative addresses or has been implemented to address a specific Transmission Issue, then consideration will be given to effectiveness, prudency, and robustness of alternative transmission solutions to determine the best transmission solution.

In accordance with their obligations under the NERC TPL standards, NERC Transmission Planners (which are generally Transmission Owners in MISO), will identify issues, investigate alternatives, and develop solutions to be rolled up to the MTEP planning process for consideration. Alternative transmission solutions may be initiated and developed within the MTEP process by MISO staff and/or other stakeholders for consideration as well. In any event, the MTEP process will consider alternative transmission solutions to address each of the identified issues when no effective non-transmission alternative has been identified or successfully implemented.

Transmission and Non-Transmission alternatives may be submitted by interested stakeholders to MISO by completing the MTEP Project Alternative Submittal Form, available: MISO Reliability Planning.

Candidate Transmission and Non-Transmission alternatives for consideration during the MTEP cycle must be submitted by the alternative deadline of May 31st, to facilitate discussion of alternatives at the June Subregional Planning Meeting.

MISO will post candidate alternatives on the MISO website (MISO Reliability Planning) no later than five days after May 31st.

MISO recommends stakeholders work directly with Transmission Owners to discuss alternatives. During the MTEP cycle and upon stakeholder request, MISO may coordinate a maximum of two additional Technical Study Task Force meetings between September 15th and the third Subregional Planning Meeting. The meetings provide a platform for Transmission Owners and stakeholders to discuss alternatives and the MTEP Issue Tracking may be used to log questions or requests.

The development of transmission and non-transmission alternatives is described in the following sections and the timeline is summarized in the following table.

Date	Action	BPM reference
September 15th	Transmission Owner/Market Participant proposed project submittals	2.4.5 Submission of Bottom-up Projects into the MTEP Project Database 6.1.1 Process Steps (Market Participant Funded Projects)
Between Sept 15th and prior to SPM3	Optional stakeholder request up to two TSTF, the meetings provide a platform for Transmission Owners and stakeholders to discuss alternatives	4.3.1.2 Development of Alternative Solutions to Projected Issues
December / January	MISO and Transmission Owners review NTA eligibility	4.3.1.2.2. 1 Contracted Demand Response or Planned Generator Interconnections
SPM 1	NTA eligibility is posted	4.3.1.2.2. 1 Contracted Demand Response or Planned Generator Interconnections
May 31st	Stakeholder alternative and NTA submission	4.3.1.2 Development of Alternative Solutions to Projected Issues
May 31st + 5 business days	MISO posts stakeholder submitted alternatives & NTA	4.3.1.2 Development of Alternative Solutions to Projected Issues
SPM 3	Non-transmission alternative agreement may be required pending transmission need	4.3.1.2.2. 1 Contracted Demand Response or Planned Generator Interconnections

4.3.1.2.1 Transmission Alternatives

4.3.1.2.1.1 Planned Redispatch, Reconfiguration, or Load Shed

Planned redispatch, reconfiguration, or load shed is used as an operator initiated and/or controlled adjustment to the system to take corrective action to address a Transmission Issue. Under certain conditions specified within the NERC TPL standards, these actions may include generation redispatch, transmission reconfiguration, or load shed (non-consequential load curtailment).

Planned redispatch, reconfiguration, or load shed may be developed by the Transmission Owners or MISO or proposed by other stakeholders. The process of developing a planned redispatch, reconfiguration, or load shed will include verification that actions are permitted within NERC standards and local planning criteria for the specified system conditions, can be implemented in a timely manner by the system operator within the timeframe allowed as specified by the Transmission Issue, and assess the impact of the next plausible event after a reconfiguration is applied. Further planned redispatch, reconfiguration, or load shed recommended to address Transmission Issues will serve as a component of the aggregate Corrective Action Plans identified in the MTEP to comply with the NERC Standards.

The use of planned redispatch, reconfiguration, or load shed as a planned solution to Transmission Issues shall be summarized at the appropriate SPM. Specific Transmission Issues being addressed by planned redispatch, reconfiguration, or load shed will be reported at the appropriate SPM if they exceed any of the following values:

- Generation Redispatch > 600 MW increment/decrement
- Transmission Reconfiguration > 1 transmission line/transformer opened
- Load Shed > 100 MW

4.3.1.2.1.2 Remedial Action Schemes

A Remedial Action Scheme (RAS) is a NERC defined term[24]. A summary of the NERC definition includes a scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). A key distinguishing characteristic of a Remedial Action Scheme is that it is automatic and occurs without any Operator Intervention. Examples of schemes not considered to be a RAS include; non-centrally controlled automatic underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS).

A Remedial Action Scheme could be developed by the Transmission Owners or MISO or proposed by other stakeholders. The process of developing a remedial action scheme will include evaluation of its inadvertent and expected operation considering NERC standards and local planning criteria, verification of its feasibility with the equipment owners impacted by the remedial action scheme, and its impact to the robustness of the system. A Remedial Action Scheme is inherently less robust than transmission expansion solutions and limits the operational flexibility of the system. The use of a RAS should typically be a temporary solution to allow for additional time to develop a more robust permanent solution. To the extent that the Transmission Issues being addressed represent projected violations of the NERC TPL Standard, the remedial action scheme proposed or recommended to address such Transmission Issues will serve as a component of the aggregate Corrective Action Plans identified in the MTEP to comply with the NERC Standards.

4.3.1.2.1.3 Transmission Expansion

Transmission expansion, which includes upgrades to existing transmission facilities and construction of new transmission facilities, represent transmission solutions that are pursued to address Transmission Issues when planned redispatch, reconfiguration, load shed and/or remedial action schemes are not feasible or effective and/or non-transmission alternatives have not been pursued or do not meet the requirements to address the Transmission Issue. Transmission expansion solutions could be developed by the Transmission Owners or MISO or proposed by other stakeholders and will take the form of transmission projects that address Transmission Issues in the most effective, prudent, and robust manner possible. The process of developing transmission projects will include, when appropriate, evaluation of alternative transmission projects to address a specific Transmission Issue or Transmission Issue set. To the extent that the Transmission Issues being addressed represent projected violations of the NERC

[24] NERC Definition: RAS Definition

TPL Standard, the transmission projects proposed or recommended to address such Transmission Issues will serve as a component of the Corrective Action Plans to facilitate compliance with the NERC TPL Standards (or when applicable, other NERC standards) for the MTEP cycle in question. A Transmission Owner who proposes to expand the Transmission System for a Transmission Issue shall provide a lead-time narrative explaining the need to move the project to Appendix A if the transmission expansion has an in-service date 5-years or more from the month following the month of its expected inclusion in expected in Appendix A.

4.3.1.2.2 Non-Transmission Alternatives

4.3.1.2.2.1 Contracted Demand Response or Planned Generator Interconnections

Prior to presenting identified issues to stakeholders at an SPM, MISO will confer with the Transmission Owners to determine which projects have drivers or other constraints that cannot be adequately or feasibly addressed by non-transmission alternatives and will then flag these projects as not compatible with non-transmission alternatives. This information will be posted with SPM 1 materials in the MTEP Issue Tracking. Non-Transmission alternatives submitted for consideration during the MTEP cycle must be submitted by the alternative deadline in Section 4.3.1.2 and do not require demand response agreement or Generator Interconnection Agreement at time of submission. For all flagged projects, the Transmission Owners and MISO will provide the specific drivers or other constraints that make the project infeasible for consideration of a non-transmission alternative. This information will be provided at an SPM for review by stakeholders. After the initial presentation of Transmission Issues (which may include information from previous MTEP cycles) and associated project proposals, a stakeholder interested in pursuing a non-transmission alternative to fully or partially address the Transmission Issues may request that MISO evaluate and communicate information regarding the minimum requirements that must be satisfied by a non-transmission alternative in order to address the Transmission Issue. Upon receipt of such a request, MISO will then work with the applicable Transmission Owner to analyze the Transmission Issue to determine such minimum requirements and provide that information to stakeholders. In order to provide the information that could enable development of either targeted demand-side solutions or efficiently located new Generation Resources, MISO will include information on the optimized bus locations and MW/Mvar amounts of injections and/or withdrawals of real and/or reactive power that would resolve certain identified Transmission Issues along with the deployment duration requirements associated with such injections and withdrawals. This information will be provided on a case-by-case basis where stakeholders express an interest in potentially pursuing demand-side or generation-side alternatives to a proposed transmission project.

MISO will use an optimization tool to determine required injection and/or withdrawal amounts in MW and/or Mvar by bus location for Transmission Issues for which a non-flagged transmission project has been proposed and stakeholders have requested MISO to provide the minimum requirements a non-transmission alternative would need to meet. The analysis will also determine the deployment duration requirements for such non-transmission alternatives. The results of this analysis will be reviewed by the applicable Transmission Owner and will then be posted and discussed along with the applicable identified Transmission Issues and alternative transmission solutions at the applicable SPM(s). Also, results will be included in the MTEP report that will be recommended to the MISO Board of Directors for approval. Stakeholders interested in developing such non-transmission alternatives can use this information to pursue such opportunities. MISO will make data available to stakeholders during the applicable SPMs.

The incorporation of generation and demand response alternatives includes the following steps:

- The load impact optimization tool will be used to determine the minimum amount of demand reduction or generation addition in MW, by bus location, needed to address a Transmission Issue.
    - For demand response non-transmission alternatives, a developer may use the information to develop a demand response non-transmission alternative and then work with the applicable Load Serving Entity, end-use customers, and when required, the responsible Transmission Operator and Transmission Planner, to develop a program and secure an executed demand response contract including development of any necessary operating guides and procedures to ensure the demand response non-transmission alternative effectively eliminates or mitigates the Transmission Issue.
    - For generation non-transmission alternatives, a developer may use the information to adjust siting for a planned future Generation Resource and will then proceed through the MISO generation interconnection process to secure a Generation Interconnection Agreement.
- To the extent the Transmission Issue involves reactive power, additional analyses may be performed to determine reactive power injection/withdrawal requirements for non-transmission alternatives.
- Implementation of NTA into the MTEP cycle:
    - Upon execution of a demand response contract, the Load Serving Entity will adjust the load forecast accordingly (i.e., taking into account how the NTA would impact the load forecast) for inclusion in the models for the next MTEP cycle. It is expected that contractual assurance and exit provisions as outlined in Attachment

FF of the tariff for demand response initiatives will be incorporated into any such demand response contract prior to adjusting load forecasts in order to ensure that the demand response solution is firm and there is ample time to address the Transmission Issue should the demand response contract desire to terminate.

- Upon execution of a Generation Interconnection Agreement, the generator will be included in future MTEP study models for the next MTEP cycle and subject to all provisions that govern generators, including the SSR process.

Should subsequent analysis by MISO and the TOs based on modeling adjustments associated with a non-transmission alternative indicate that the Transmission Issue(s) in question has been eliminated or mitigated in the same MTEP cycle in which it was submitted, MISO and the Transmission Owner will evaluate deferring, de-scoping, or withdrawing the previously proposed transmission project as appropriate in the same manner as would be done if other need drivers were eliminated. Where subsequent analysis occurs in the next planning cycle after NTA agreements have been executed and MISO models have been updated to include the impact of the NTA, and the NTA results in mitigation or elimination of the Transmission Issue(s), MISO and the Transmission Owners will confirm mitigation or elimination of the Transmission Issue and then defer, de-scope, or withdraw the proposed transmission project as appropriate, provided that there are no other proposed drivers of the project. However, in some cases, subsequent analysis could be performed by MISO and the Transmission Owners for projects with a Planning Review Status of “Recommended” (i.e., Targeted Appendix A projects) and “Approved” (i.e., Appendix A projects) subject to the feasibility of considering an NTA at that stage of the planning process. Actual decisions to withdraw, de-scope, or defer a transmission project are always made on a case-by-case basis considering all pertinent factors, including such things as other transmission project drivers and the status of the transmission project at the time NTAs are firm. The evaluation may require that the necessary agreement (demand response agreement or Generator Interconnection Agreement) is completed by SPM 3 and is determined through discussion with Transmission Owner, MISO, and submitter of the NTA.

It is important to note that when consideration is given to deferring, de-scoping, and/or withdrawing a previously proposed transmission project for any reason, consideration will always be given to the following specific factors:

- Other drivers for the original proposed transmission project (e.g., aging and condition, operational flexibility, etc.).
- Impacts on future projects in the MTEP (i.e., impact on the interdependence of multiple transmission projects within MTEP over a period of time).
- Impacts on other Transmission Issues of deferring, de-scoping, or withdrawing the original transmission project given the NTA will be implemented.
- Impact on Transmission System robustness of deferring, de-scoping, or withdrawing the original transmission project given the NTA will be implemented.
- Impact of NTA on NRIS deliverability*.
- Result of no-harm test of NTA*.
- Lead time for NTA vs. required in-service date*
- NTA duration capabilities vs. NTA duration requirements*
- NTA deployment provisions in the executed contract*
- NTA termination provisions in the executed contract*

*Embedded in the modeling adjustments and subsequent analyses.

4.3.1.3 Selection of the Best Transmission Solutions for Projected Issues

When no non-transmission alternatives are identified or pursued for a specific Transmission Issue or Transmission Issue set, only alternative transmission solutions will be considered. Once the bottom-up planning process has yielded alternative transmission solutions to these identified Transmission Issues, the process will evaluate all solutions and recommend the best solutions. When project lead times require projects to be approved in the current MTEP cycle in order to meet the required in-service date, the planning process will recommend solutions to the MISO Board of Directors via the MTEP, and if the MTEP is approved, those solutions will become transmission projects in Appendix A of the MTEP report in accordance with Section 2.4 of this BPM. When project lead times do not require final commitment to a specific solution in the current MTEP cycle, the best solution at the time will be selected and placed into Appendix B of the MTEP report. Placing transmission solutions in Appendix B ensures there are Corrective Action Plans for projected TPL reliability issues as required by the NERC TPL standards. However, as conditions change, Appendix B projects may be modified, removed, or replaced with other projects when appropriate.

4.3.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owner(s) Agreement, the MISO Transmission System is to be planned to meet local, regional, and NERC planning standards. The bottom-up planning analysis performed by the MISO planning staff tests the simulated performance of the system against the NERC Standards as well as regional standards and Local Planning Criteria. Studies to determine compliance with local requirements are handled by the local Transmission Owner(s), unless agreed upon by the local Transmission Owner and MISO. The branch Loading limits, and Bus voltage limits established by a specific Transmission Owner for their own transmission facilities and system are enforced by MISO.

The Transmission Owner has the exclusive authority to establish and modify its local transmission planning criteria at any time. Annually, the Transmission Owner files updates to its local transmission planning criteria as part of the FERC Form 715 filing. In addition, whenever the Transmission Owner updates local transmission planning criteria, the Transmission Owner provides the updated local transmission planning criteria to MISO. As the Transmission Provider, MISO will post the new Transmission Owner criteria on the planning page of the MISO website or provide a link to the Transmission Owner's website. Concurrently, MISO will post a notice on the planning page of MISO's OASIS website indicating MISO has received updated local Transmission Owner's planning criteria.

The effective date of the Transmission Owner's local transmission planning criteria will be the date that the Transmission Owner submits revised criteria to MISO. The Transmission Owner should use best efforts in notifying MISO that the Transmission Owner is in the process of modifying its local transmission planning criteria thirty (30) Days or more, prior to when the Transmission Owner expects to submit the modified criteria to MISO.

In the event that a modification to a Transmission Owner's Local Planning Criteria conflicts with any provisions of an established MISO Business Practice Manual, in addition to the process in this section, MISO will work directly with the Transmission Owner to discuss and attempt to resolve the differences. If necessary, MISO will convene the applicable MISO stakeholder forum to address the necessary modifications to the Business Practice to enable consistency with the specific Transmission Owner modifications to local transmission planning criteria.
Section 4.5 of BPM-015 Generation Interconnection indicates when Transmission Owner local planning criteria updates will be used in Generation Interconnection studies.

Any difference in study methodologies of existing units in the MTEP and DPP cases based on Transmission Owner Local Planning Criteria should be made clear in the Transmission Owners posted Local Planning Criteria. If a Transmission Owner invokes Local Planning Criteria in a concurrent DPP study, MISO may require the Transmission Owner(s) demonstrate how the same Local Planning Criteria are applied to their MTEP reliability planning studies. In cases when MISO does not require such demonstration, MISO and the Transmission Owner(s) will provide a written explanation as to why no demonstration is required.

All system elements that constitute the Transmission System of MISO and the MISO Reliability Area, including tie lines to neighboring systems, are monitored in all planning simulations. In addition, first tier non-MISO Member transmission systems are monitored and, when deemed appropriate, specific elements beyond first tier non-MISO Member transmission systems may be monitored as well. For each monitored branch, the Transmission Owner will provide, at a minimum, a Normal Rating and an Emergency Rating, where such ratings are expressed in MVA at the nominal operating voltage. The Normal Rating represents the maximum Load that may be carried by a branch on a continuous basis and the Emergency Rating represents the maximum Load that may be carried by a branch during abnormal system conditions (i.e., one or more system elements out of service due to forced outages, etc.), but not continuously. The Emergency Rating must be greater than or equal to the Normal Rating.

The Transmission Owner may also provide, at their option, a higher emergency rating for any specific monitored branch. The higher emergency rating is expressed in MVA at the nominal operating voltage and also includes a maximum loading duration. The Short-term Emergency Rating represents the maximum Load that may be carried by a branch on an infrequent basis and for a short period of time not to exceed the associated rating duration. In addition to branch ratings, the Transmission Owner will provide upper and lower normal voltage limits and upper and lower emergency voltage limits to be applied to each monitored Bus. These Bus voltage limits may be expressed in kV or per unit of the nominal operating voltage.

Under system intact conditions, branch loading will be monitored against Normal Ratings and Bus voltage will be monitored against normal Bus voltage limits. Under contingent conditions, branch loading will be monitored against Emergency Ratings and Bus voltages will be monitored against emergency Bus voltage limits. For contingent events that are defined by a single contingency or multiple contingencies occurring simultaneously or near simultaneously (e.g., a permanent transmission circuit fault followed by a stuck breaker and the subsequent tripping of a second transmission circuit a few cycles later by a breaker failure relay scheme, etc.), if post contingent steady-state Loading is above the highest applicable rating (Emergency Rating or, if available, higher emergency rating) or post contingent steady-state voltages are outside the emergency Bus voltage thresholds, then a Corrective Action Plan cannot include post contingency manual system adjustments (including curtailment of firm interchange) or post contingency manual non-consequential Load curtailment since such action requires time to implement and would thus result in a violation of Header Note f in Table 1 of TPL-001 that prohibits applicable facility ratings from being exceeded on a steady state basis.

However, if a higher emergency rating exists and i) the post contingent steady state Loading is above the Emergency Rating but below the higher emergency rating, ii) the post contingent steady-state voltage magnitudes are within the emergency Bus voltage limits, and iii) Applicable Reliability Standards allow for system adjustments or firm Load curtailment to address the contingency in question, then manual system adjustments or manual firm Load curtailment may be used so long as MISO or the TOs can demonstrate that such manual system adjustments and/or manual firm Load curtailment can be performed within the duration associated with the higher emergency rating that will return the Loading to a level less than or equal to the Emergency Rating within the duration associated with the higher emergency rating in accordance with Header Note e of Table 1 of TPL 001. MISO and the TOs will coordinate as to who and how this determination will be made.

4.3.3 Baseline Models - Data Sources and Assumptions

MISO Baseline Reliability study models will typically include power-flow models reflective of two-year out, five-year out, and ten-year out system conditions in accordance with the NERC TPL standards. For two-year out and five-year out conditions, models will be developed both for the system peak demand case and for at least one off-peak case in accordance with the NERC TPL standards. Other variations of these may also be used as appropriate, based on the stakeholder input for a given planning cycle.

4.3.3.1 Topology

The system topology in the bottom-up planning models will reflect the expected system condition for the planning horizon in question. For models used to identify projected system issues with no system improvements, the topology will represent existing facilities, plus system expansions associated with projects with a Planning Review Status of “Approved”, less any facilities where commitments have been made to retire such facilities. For models used to test the final Corrective Action Plan for compliance with Applicable Reliability Standards and Transmission Owner planning criteria, the topology will represent existing facilities; plus, all projects with a Planning Review Status of “Approved”, “Recommended”, or “Validated”; less any facilities where commitments have been made to retire such facilities.

Future transmission upgrades are removed from the model if they have a Planning Review Status of "Not Approved" or "Withdrawn", or if they do not meet the inclusion criteria above. The non-MISO system representation will be based on the latest external system models for the planning horizon.

4.3.3.2 Generation, Load, and Interchanges

All existing generators and future generators with a filed Interconnection Agreement and in-service date prior to the point in time represented by the model will be included in the model. Any additional generation needed to serve future Load growth will be modeled based on input from future generation modeling processes described *in Section 4.4 of this BPM*. New information on generators external to the MISO system shall be received through coordinated data exchange with such external entities and they will also be modeled appropriately. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on their start date, based on the information provided by the Generator Owners through the System Support Resource study process, *see Section 6.2 of this BPM*. Units with approved Attachment Y Notices that have waived their interconnection rights (i.e., retired) will remain offline indefinitely. Units with approved Attachment Y Notices that have not waived their interconnection rights (i.e., suspended) will remain offline for the first three (3) years following their start date and after the three (3) years they will be available for dispatch.

In any event, sufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon. The Load Forecast information is ultimately provided by the LSE either directly or through the Transmission Owner. This information is reviewed and compared against Load data from NERC series models and Load Forecast information filed with FERC and State regulatory agencies. Interchange and transaction data are also updated via the model building process which will include any new firm transactions or changes from the Transmission Service planning process.

A firm LBA dispatch is simulated for MISO and external systems for the baseline reliability studies. A firm LBA dispatch requires that firm resources contractually obligated to serve the Load of a particular LSE must be used and should be economically dispatched to the degree possible subject to generating unit, transmission, and LBA power balance constraints. A security constrained economic dispatch of MISO resources may be used for voltage stability and transient angular stability analyses to ensure market dispatches are secure from a power system stability and cascading outage perspective.

4.3.4 Bottom-up Planning Contingencies

4.3.4.1 Contingencies Evaluated in Support of Annual Reliability Assessments

Regional contingency files are developed by MISO planning staff collaboratively with Transmission Owner(s) and external entities and supplemented by information obtained from stakeholders at SPMs, as appropriate. The list of contingencies will include events described under NERC TPL-001 Table 1 plus any applicable local or regional planning standards, criteria, or guidelines. NERC TPL contingencies classified as planning events (i.e., denoted by the letter “P” followed by a number) that are violated in planning studies must be mitigated with a Corrective Action Plan. NERC TPL contingencies classified as extreme events must be studied and the results must be evaluated with respect to impact on the system. Should the simulation of an extreme event contingency result in cascading, it is necessary to evaluate possible actions that can be taken to mitigate the impact of the event. Below is a list and description of the NERC TPL contingency categories tested:

- NERC category P0: System intact or no contingency event.
- NERC category P1 (P1-1 through P1-5): Loss of a Single Element due to a Three-phase Fault

  Contingencies include generating units (P1-1); transmission circuits (P1-2); transmission transformers (P1-3); transmission shunt devices (P1-4), where shunt devices include shunt capacitors, shunt reactors, static var compensators, and similar shunt devices; and loss of a single pole on an HVDC line (P1-5). Series reactors and series capacitors should be treated as transmission circuits if they have an independent protective zone apart from a transmission circuit or transformer. All Load directly served by the contingent facility should be modeled as interrupted (i.e., consequential Load loss). In addition, all other elements within the protective zone associated with the contingent facility (e.g., shunt reactors, tapped transmission transformers, etc.) should be modeled as interrupted following the contingency. Manual System adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues associated with P1 contingencies (except in limited circumstances as detailed in the NERC TPL Footnote 12, and Attachment I).

Other manual system adjustments (e.g., redispatch, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P1 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments required to reduce branch Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating. In order to ensure a robust system, P1 contingencies for off-peak cases will be simulated both under pre-contingency system intact conditions and pre-contingency N-1 conditions to account for select planned maintenance outages that will occur during off peak periods. The relevant planning event and system impacts shall be available as supporting information for proposed Corrective Action Plans.

- NERC category P2-1: Opening a Line Section without a Fault
  The primary purpose of this contingency is to test the ability of the system to serve Load connected to a transmission circuit from one end with the opposite terminal open. Therefore, these contingencies apply only to network transmission protection zones that include directly connected Loads (primarily transmission circuit protective zones and in rare cases, transformer protective zones where Load may be served from a tertiary winding). These contingencies do not apply to generating units although generator auxiliary Load could be served in the generating unit protective zone. For two-terminal network transmission protection zones that include directly connected Loads, two contingencies are required, one for each terminal open. For a three-terminal network transmission protective zone, three contingencies are required, one for each terminal open. It is not necessary to consider contingencies where two terminals are open on a three-terminal transmission protective zone. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading or Bus voltage issues associated with P1 contingencies[25].
- NERC category P2-2: Loss of a Bus section due to a Phase-to-ground Fault
  Contingencies include straight Buses and each of the two physical Buses associated with a double Bus configuration (e.g., breaker-and-a-half and/or double-breaker configurations). All Load and shunts served directly by the Bus section should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). For double-Bus configurations, all network elements that connect to one of the physical Buses directly through a single circuit breaker rather than through a position between two circuit breakers should be modeled as open for the applicable physical Bus

[25] Except under limited circumstances explained in Footnote 12 and Attachment I of the standard

contingency. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV Bus section P2-2 contingencies, non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues. For HV Bus section P2-2 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P2-2 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P2-3: Internal Circuit Breaker Single Phase-to-ground Fault (non-Bus tie circuit breakers only)
  Contingencies include all circuit breakers that are not Bus tie circuit breakers and represent a single phase-to-ground fault within the overlap of the protective zones on each side of the circuit breaker, thus resulting in a loss of both protective zones. All Loads and shunts served directly by each of the two protective zones should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). Manual System adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV circuit breaker P2-3 contingencies, non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues. For HV circuit breaker P2-3 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

  However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P2-3 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch

Loading below the Emergency Rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P2-4: Internal Circuit Breaker Single Phase-to-ground Fault (Bus tie circuit breakers only)
  Contingencies include all circuit breakers that are Bus tie circuit breakers and represent a single phase-to-ground fault within the overlap of the Bus protective zones on each side of the circuit breaker, thus resulting in a loss of both Buses. All Loads and shunts served directly by each of the two Buses should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P2-4 contingencies.

  Manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P2-4 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.
- NERC category P3: Loss of a Generating Unit followed by System Adjustments followed by Loss of another Element due to a Three-phase Fault.
  Contingencies include loss of any generating unit followed by allowable system adjustments followed by the loss of any of the following additional elements:
  - P3-1: Generating unit due to a three-phase fault
  - P3-2: Transmission circuit due to a three-phase fault
  - P3-3: Transmission transformer due to a three-phase fault
  - P3-4: Shunt device due to a three-phase fault
  - P3-5: Single pole block of DC line due to a line-to-ground fault

  All Load directly served by the second contingent element and other elements within the protective zone associated with the second contingent element should be modeled as interrupted following the contingency. Manual system adjustments and manual non-consequential Load curtailment subsequent to the second contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch loading issues associated with P3 contingencies.

Other manual system adjustments (e.g., redispatch, etc.) can be used following the loss of the generator to prevent branch loading issues following the loss of the second contingent element.

- NERC category P4 (P4-1 through P4-5): Loss of an Element followed by a Stuck Breaker followed by Loss of an additional Element where the Stuck Breaker is not a Bus-tie Breaker.
  Contingencies include loss of any of the following elements followed by a stuck breaker that triggers the loss of a second element where such stuck breaker is not a Bus-tie breaker (i.e., the two contingent elements are not both Bus sections).
  - P4-1: Generating unit due to a phase-to-ground fault
  - P4-2: Transmission circuit due to a phase-to-ground fault
  - P4-3: Transmission transformer due to a phase-to-ground fault
  - P4-4: Shunt device due to a phase-to-ground fault
  - P4-5: Bus section due to a phase-to-ground fault

All Loads served directly by each of the two contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with the contingent elements should be modeled as interrupted following the fault. For dynamic studies, if the circuit breaker consists of independent pole operation (independent mechanisms and trip coils for each pole), the contingency may assume failure of only one pole to trip so long as the failed pole is assumed to be on the faulted phase. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV P4-1 through P4-5 contingencies (i.e., the faulted element is an EHV facility as defined above and in the NERC TPL standard), non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues. For HV P4-1 through P4-5 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

However, the use of manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P4-1 through P4-5 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P4-6: Loss of a Bus section due to a Phase-to-ground Fault followed by a Stuck Breaker followed by Loss of a second Bus where the Stuck Breaker is a Bus-tie Breaker.

  Contingencies include loss of an element followed by a stuck breaker that triggers the loss of a second element where such stuck breaker is a Bus-tie breaker and the contingent elements are both Bus sections. For dynamic studies, if the circuit breaker consists of independent pole operation (independent mechanisms and trip coils for each pole), the contingency may assume failure of only one pole to trip so long as the failed pole is assumed to be on the faulted phase. All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments and manual non-consequential Load curtailment subsequent to the second contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P4-6 contingencies.

  However, all manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P4-6 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the allowable system adjustments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC category P5 (P5-1 through P5-5): Loss of a Transmission Element due to a Phase-to-ground Fault followed by Failure of a Non-redundant Protective Relay that Triggers Delayed Fault Clearing via Remote Backup Protection on Adjacent Transmission Elements.
  Contingencies include loss of any of the following elements followed by a non-redundant relay failure that triggers the loss of additional elements and delayed fault clearing via remote backup tripping.
  - P5-1: Generating unit due to a phase-to-ground fault
  - P5-2: Transmission circuit due to a phase-to-ground fault
  - P5-3: Transmission transformer due to a phase-to-ground fault
  - P5-4: Shunt device due to a phase-to-ground fault
  - P5-5: Bus section due to a phase-to-ground fault

  All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments and manual non-consequential Load curtailment are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Furthermore, for EHV P5-1 through P5-5 contingencies (i.e., the faulted element is an EHV facility as defined above and in the NERC TPL standard), non-consequential firm Load curtailment and/or curtailment of firm transmission service are not allowed as system adjustments to address branch Loading issues. For HV P5-1 through P5-5 contingencies, non-consequential Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues.

  However, manual system adjustments or manual firm Load curtailments can only be used on a post contingent basis to address branch Loading issues resulting from P5-1 through P5-5 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the system adjustments or firm Load curtailments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.
- NERC category P6 (P6-1 through P6-4): Loss of an Element followed by System Adjustments followed by Loss of another Element due to a Three-phase Fault.

Contingencies include loss of any element from the list below followed by allowable system adjustments followed by the loss of a second element from the list below:

- P6-1: Transmission circuit due to a three-phase fault
- P6-2: Transmission transformer due to a three-phase fault
- P6-3: Shunt device due to a three-phase fault
- P6-4: Single pole block of DC line due to a line-to-ground fault

All Load directly served by all contingent elements should be modeled as interrupted following the fault (i.e., consequential Load loss, etc.). In addition, all other elements within the protective zone associated with all contingent elements should be modeled as interrupted following the fault. Manual system adjustments (e.g., redispatch, curtailment of firm transmission service, etc.) can be used following the loss of the first contingent element to prevent branch loading issues or steady state voltage issues following the loss of the second contingent element.

- NERC category P7 (P7-1 through P7-2): Loss of any Two Transmission Circuits on a Common Structure or Loss of a Bipolar HVDC Circuit. Contingencies include loss of any of the following:
  - P7-1: Two transmission circuits on common structures due to a line-to-ground fault
  - P7-2: Loss of a DC bipolar line for a line-to-ground fault

All Load directly served by both contingent elements and other elements within the protective zone associated with each contingent element should be modeled as interrupted following the contingency. Manual system adjustments and non-consequential Load curtailment subsequent to the contingency are not allowed to address issues where post contingent steady-state voltages fall outside of emergency voltage limits. Non-consequential firm Load curtailment and/or curtailment of firm transmission service are allowed as system adjustments to address branch loading issues associated with P7 contingencies.

However, all manual system adjustments (e.g., redispatch, curtailment of firm transmission service, curtailment of non-consequential Load, etc.) can only be used on a post contingent basis to address branch Loading issues resulting from P7 contingencies if i) a higher emergency rating is provided for the branch, ii) the post contingent steady state flow on the branch is below the higher emergency rating, and iii) the allowable system adjustments required to reduce branch Loading below the emergency rating can be made within the maximum duration associated with the higher emergency rating.

- NERC Steady-state and Stability Extreme Event: Category P3 and P6 contingencies without any allowance for system adjustments in between the contingencies.
- NERC Steady-state Extreme Event: Loss of three or more transmission circuits on common structures.
- NERC Steady-state Extreme Event: Loss of all transmission circuits on a common right-of-way.
- NERC Steady-state Extreme Event: Loss of a switching station or substation (loss of one complete voltage level plus all connecting transformers).
- NERC Steady-state Extreme Event: Loss of all generating units at a generating station.
- NERC Steady-state Extreme Event: Loss of a large Load or major Load center, when applicable.
- NERC Steady-state Extreme Event: Loss of two generating stations from a common root cause, when applicable.
- NERC Stability Extreme Event: Category P4 contingencies assuming three-phase fault instead of phase-to-ground fault.
- NERC Stability Extreme Event: Category P5 contingencies assuming three-phase fault instead of phase-to-ground fault.

4.3.4.2 Rationale for Contingencies Selected as More Severe

The NERC TPL standards require that studies are to be performed and evaluated only for those contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information.

MISO applies the following principles in contingency selection:

- When feasible, MISO will evaluate all contingencies for each category in Table 1 of NERC TPL 001 for the MISO footprint and all adjacent tier-1 Transmission Planner and/or Planning Coordinator footprints.
- MISO planning staff will rely on the expertise of the planning staffs of MISO Transmission Owner(s) for their input regarding specific contingencies that should be studied when it is not feasible to study all contingencies.
- MISO will consult external Transmission Planners and Planning Coordinators, particularly those representing adjacent tier-1 systems, to determine which external contingencies should be studied when it is not feasible to study all contingencies.

- For contingencies involving the loss of more than one element under two independent triggering events (e.g., P3 and P6 contingencies, etc.), MISO will evaluate an extensive list of contingency combinations to determine the combinations of facilities that have a greater probability of adversely impacting the system or otherwise producing more severe results

Consistent with these contingency selection principles, the following contingencies will be analyzed at a minimum:

- All NERC category P1 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P1-1: Loss of Generator due to 3ϕ fault
  - P1-2: Loss of Transmission Circuit due to 3ϕ fault
  - P1-3: Loss of Transformer due to 3ϕ fault
  - P1-4: Loss of Shunt Device due to 3ϕ fault
  - P1-5: Loss of Single Pole of HVDC Line due to line-to-ground fault
- All NERC category P2 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P2-1: Opening of a Transmission Circuit terminal without a fault
  - P2-2: Loss of Bus section due to ϕ-to-ground fault
  - P2-3: Loss of two Elements due to internal circuit breaker ϕ-to-ground fault
  - P2-4: Loss of two Buses due to internal tie breaker ϕ-to-ground fault
- The set of NERC category P3 contingencies determined to provide the most severe impacts to the system:
  - P3-1: P1-1 followed allowable system adjustments followed by second P1-1
  - P3-2: P1-1 followed by allowable system adjustments followed by P1-2
  - P3-3: P1-1 followed by allowable system adjustments followed by P1-3
  - P3-4: P1-1 followed by allowable system adjustments followed by P1-4
  - P3-5: P1-1 followed by allowable system adjustments followed by P1-5

    It is important to note that it is not necessary to simulate the same two contingent elements (a generator plus another element) in two separate P3 contingencies where the order of contingency occurrence is reversed.
- All NERC category P4 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, including the following:
  - P4-1: A P1-1 event followed by stuck breaker* followed by breaker failure relay operation**

- P4-2: A P1-2 event followed by stuck breaker* followed by breaker failure relay operation**
- P4-3: A P1-3 event followed by stuck breaker* followed by breaker failure relay operation**
- P4-4: A P1-4 event followed by stuck breaker* followed by breaker failure relay operation**
- P4-5: A P2-2 event followed by stuck breaker*** followed by breaker failure relay operation**
- P4-6: A P2-2 event followed by stuck breaker**** followed by breaker failure relay operation**

NOTES:

**In dynamic studies, for circuit breakers with independent pole operated mechanisms, assume only one pole fails to trip, otherwise assume all three poles fail to trip*

***Independent contingencies should be conducted for each individual breaker protecting the applicable contingent element (e.g., for a two-terminal transmission line between two ring Buses, there are four breakers protecting the line, two at each terminal, and thus four P1-2 contingencies would be studied for this single facility, etc.).*

****P4-5 contingencies apply to Bus faults where the stuck breaker is not a Bus tie breaker.*

*****P4-6 contingencies apply to Bus faults where the stuck breakers is a Bus tie breaker*

- All NERC category P5 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints where one or more non-redundant protection system components exist, including the following:
  - P5-1: A P1-1 event followed by non-redundant relay component failure* followed by delayed remote clearing
  - P5-2: A P1-2 event followed by non-redundant relay component failure* followed by delayed remote clearing**
  - P5-3: A P1-3 event followed by non-redundant relay component failure* followed by delayed remote clearing**
  - P5-4: A P1-4 event followed by non-redundant relay component failure* followed by delayed remote clearing**

- P5-5: A P2-2 event followed by non-redundant relay component failure* followed by delayed remote clearing**

  NOTES:
  **Non-redundant relay components include protective relays (21, 87, 50, 51, 67, 59, 32), auxiliary relays (94), lockout relays (86), and communications relays (85). P5 contingencies do not apply to facilities with fully redundant relays at all terminals. For a specific facility, a separate P5 contingency must be executed for each distinct impact (e.g., failure of tripping at one terminal vs. the other, etc.). P5 contingencies that have an identical impact to P4 contingencies (e.g., failure of a breaker trip coil, etc.) may reference the results from the corresponding P4 contingency analysis.*

  ***For P5 contingencies on multi-terminal facilities other than Bus sections (P5-2 and P5-3 contingencies), the fault location should be modeled at each terminal that could possibly not trip due to a non-redundant relay component failure. For failure modes that prevent tripping and breaker failure initiation at a single terminal only (e.g., failure of a non-redundant auxiliary tripping relay at one terminal of a line with a DCB protection scheme, etc.), the relay failure should be assumed to occur at the terminal where the fault is simulated. For failure modes that prevent tripping at both terminals (e.g., failure of a non-redundant transformer differential relay for a Bus fault internal to the transformer protective zone but external to the transformer, etc.), a failure of both terminals to trip for a specific event should be simulated. When both terminals fail to trip, remote fault clearing from various lines could be sequential rather than simultaneous, and this should be simulated (e.g., remote backup tripping at the terminal opposite of the fault may clear on zone 3 time instead of zone 2 time, infeed effects may cause sequential tripping of remote backup protection on lines at the terminal opposite of the fault, etc.).*

- The set of NERC category P6 contingencies determined to provide the most severe impacts to the system
  - P6-1: A P1-2 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency.
  - P6-2: A P1-3 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency.
  - P6-3: A P1-4 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency/

- P6-4: A P1-5 event followed by allowable system adjustments followed by either a P1-2, P1-3, or P1-4 contingency

  It is important to note that it is not necessary to simulate the same two contingent elements in two separate P6 contingencies where the order of contingency occurrence is reversed.

- All NERC category P7-1 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints, where the two contingent transmission circuit share the same structures for a length of one mile or more.
- All NERC category P7-2 contingencies for facilities within MISO or within adjacent Planning Coordinator footprints.
- All NERC steady-state extreme event contingencies involving the loss of three or more transmission circuits on common structures within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of all transmission circuits on a common right-of-way within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of a switching station or substation (loss of one complete voltage level plus all connecting transformers) within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of all generating units at a generating station within MISO or an adjacent Planning Coordinator footprint.
- All NERC steady-state extreme event contingencies involving the loss of a large Load or major Load center within MISO or an adjacent Planning Coordinator footprint where MISO staff working in consultation with applicable Transmission Owner(s) or adjacent Planning Coordinators determine that the probability and impact of such an occurrence are significant.
- NERC steady-state extreme event involving the loss of two generating stations from a common root cause within MISO or an adjacent Planning Coordinator footprint where MISO staff working in consultation with applicable Transmission Owner(s) or adjacent Planning Coordinators determine that the probability and impact of such an occurrence are significant.
- All NERC stability extreme event contingencies defined as MISO P4 contingencies assuming three-phase fault instead of phase-to-ground fault.
- All NERC stability extreme event contingencies defined as MISO P5 contingencies assuming a three-phase fault instead of phase-to-ground fault.

4.3.4.2.1: MISO Default Methodology for Selecting TPL-001-5.1 P5 Contingencies for Evaluation

Please *see Appendix F of this BPM*, which outlines the MISO Default Methodology for selecting TPL-001-5.1 P5 contingencies. A Transmission Planner may specify their own methodology or point to the default MISO methodology *as outlined in Appendix F of this BPM,* for developing P5 contingencies. MISO will use whichever methodology has been chosen by the Transmission Planner, but to the extent the Transmission Planner selects their own methodology, the MISO role will be limited to simply implementing the TPL P5 contingencies provided to MISO by the Transmission Planner. In the event the Transmission Planner points to the default MISO methodology, MISO will provide data from the annual fast fault screening study to the Transmission Planner to be used to develop the P5 contingency list and forward back to MISO prior to the next MTEP cycle.

4.3.5 Bottom-up Planning Reliability Testing

Reliability testing of the planned system focuses on ensuring that the Transmission System is reliable in the foreseeable future and complies with national and regional reliability standards (including NERC TPL standards), as well as local and Transmission Owner planning criteria. The Transmission System is analyzed under multiple planning horizons and varying Load conditions. The planning horizons studied include two-years out, five-years out, and ten-years out. The specific Load cases studied in each specific planning horizon are driven by the NERC TPL standards and may vary from year to year to ensure the planning process considers pertinent future scenarios. Specific Load cases include peak Load cases, shoulder Load cases, and light Load cases. Steady-state analysis is performed on an LBA centric contractual dispatched power-flow model to avoid i) the need to implement a Corrective Action Plan for a problem resulting from the non-firm use of the system or ii) counting on a non-firm transaction from masking a problem that needs a Corrective Action Plan when the system is operated based on a firm contractual dispatch. Steady-state analysis includes both steady-state analysis, as described *in Section 4.3.5.2 of this BPM*, and transfer analysis as described *in Appendix N of this BPM*. Transient angular stability analysis which is described *in Section 4.3.5.3 of this BPM* is performed assuming a market-based Security Constrained Economic Dispatch (SCED) to ensure that anticipated non-firm use of the system by the market will not create a risk of transient instability. Should the SCED uncover a transient stability issue, an appropriate limitation or Corrective Action Plan will be considered to address the issue.

4.3.5.1 Steady-State Analysis

Steady-state Contingency Analysis will be performed on the baseline planning models with no system improvements to test the contingencies of various categories described *under Section 4.3.4 of this BPM*. Thermal limit and voltage limit violations will be screened based on facility ratings and voltage limits submitted by Transmission Owner(s) as discussed *in Section 4.3.2 of this BPM*. To the extent a Transmission Owner does not specify voltage limits, MISO will use the voltage limits in the default criteria outlined *in Appendix K of this BPM*. In addition, the Transmission Owner may elect to point to the MISO default criteria *in Appendix K of this BPM* to establish voltage limits for their footprint. Any thermal overloads greater than one-hundred twenty-five (125%) percent of the emergency rating of a Load carrying facility will be flagged and reviewed against applicable Interconnected Reliability Operating Limit (IROL) criteria to determine if an IROL should be created for the facility.

4.3.5.2 Steady-State Voltage Stability Analysis

In addition to contingency analysis, a separate steady-state voltage stability analysis is also performed in order to identify voltage stability limits and power transfer margins. This will help identify areas with voltage instability issues. The appropriate system conditions and areas to study are selected based on the stakeholder and system operator input solicited at the beginning of the planning cycle. Appropriate system conditions are those conditions that align with conditions modeled in TPL-001 baseline and/or sensitivity analysis. The following general study procedures are used for this analysis:

- Specific scenarios are selected for PV and/or QV analyses. Scenarios include transfer levels and interfaces, system conditions (including Load, dispatch, contingencies, and status of reactive resources), and study horizons. The MTEP models are used as the basis for performing the transfer simulations and associated PV and QV analysis.
- For each specific scenario, the study will monitor Bus voltages, reactive reserves at applicable generating units, and flows on applicable branches and interfaces under appropriate system stress conditions (critical contingencies and significant transfer levels).
- For each specific scenario modeled, the study will identify and document transfer limits based on voltage stability margins under PV analysis and areas with exhausted or limited reactive reserves under QV analysis. Voltage stability margins are based on the voltage stability criteria provided by the Transmission Owner or the MISO default voltage stability criteria *in Appendix K of this BPM* if the Transmission Owner provides no criteria or points to the MISO criteria.

4.3.5.3 Dynamic Stability Analysis

MISO will perform dynamic stability analysis which includes transient angular stability analysis, transient voltage stability analysis, and other transient voltage analysis (e.g., FIDVR) for the contingencies described *in Section 4.3.4 of this BPM*. The contingencies will simulate the initiating fault, generator dynamic response, generation and transmission protection system response, high speed reclosing response when applicable, and subsequent delayed clearing when applicable (P4, P5, and certain extreme event contingencies).

MISO will enforce the damping ratio and critical clearing time margin criteria provided by each Transmission Owner for contingencies in their area, or in the absence of such criteria, will apply the default damping ratio and critical clearing time margin criteria specified *in Appendix K of this BPM*. For contingencies in multiple Transmission Owner areas, MISO will use the most conservative criteria.

A dynamic study model will monitor Bus voltage magnitudes and phase angles, branch power flows, and apparent impedance trajectories at Load responsive line relay[26] terminals. The dynamic study will calculate damping ratios, identify generating units pulling out of synchronism, simulate tripping of generating units due to power swings or inadequate voltage ride-through capability, simulate the tripping of non-faulted transmission lines due to stable or unstable power swings using actual or generic relay models in accordance with the NERC TPL standards, simulate Bus voltage response including fast voltage collapse, transient voltages due to power swings, and/or delayed voltage recovery. MISO will use the generic relay models within PSS®E for dynamic simulation of power swing trips as an initial screening tool and will then request the actual trip characteristics from the Transmission Owner should a trip be simulated to confirm a power swing trip will actually occur. The clearing times used to simulate protection system response will be determined by Transmission Owner(s) based on worst case breaker clearing times, worst case relay operating times, breaker failure timer settings, remote backup protection timer settings, and the appropriate critical clearing time margin.

4.3.5.4 Results Management

MISO manages results from the MTEP study in a Results database. The results database is populated with results from analysis, comments on results from stakeholders, and mappings of results to projects which have been determined to have resolved the identified system issue.

[26] Load responsive relay elements are relay elements that are sensitive to Load currents and power swings as well as short-circuit faults and typically include impedance (distance), overcurrent, and directional overcurrent phase relay elements, but not ground or negative sequence relay elements or differential relay elements.

4.3.6 Consideration of Planned Outages in the Near-Term Transmission Planning Horizon

MISO performs an assessment of impacts of selected planned outages that are expected to have a severe impact on system performance in accordance with requirements of NERC Standard TPL-001-5.

4.3.6.1 Sources of Planned Outages

Known planned outages are those for which there exists an outage schedule (via CROW) or where the Transmission Planner has developed a plan for the likely expected occurrence in the planning horizon. Such a plan may be associated with equipment maintenance, upgrades or new construction and may be developed to address conditions that require advance preparation to accommodate the outage.

Planned Outages include:

Transmission Outages

- CROW outage scheduling system – Planned transmission outages that are scheduled in the MISO Outage Coordination process are required to be submitted at least one year in advance. This enables MISO to fully assess the impacts in the Operating Horizon but does not ensure sufficient coverage for the five-year Near-Term Transmission Planning Horizon due to the limited advance notice requirement.
- MTEP projects that are included in MTEP Appendix A are commitments to build to meet needs in the five-year Near-Term Transmission Planning Horizon. Outages that are required to enable transmission upgrades and new facility construction by the expected in-service date are to be provided by the Transmission Planner to the Planning Coordinator in response to the annual MTEP cycle data request from the Planning Coordinator.

Generation Outages

- CROW outage scheduling system – Generation planned maintenance outages (10MW and above) that are scheduled in the MISO Outage Coordination process are required to be submitted to MISO for a rolling 24-month period *per section 4.1 of the MISO BPM-008 Outage Operations Business Practices Manual*. This enables MISO to fully assess the impacts in the Operating Horizon but does not ensure sufficient coverage for the five-year Near-Term Transmission Planning Horizon due to the limited advance notice requirement.

- Regularly recurring outages of nuclear power plant facilities may be expected to occur but not scheduled. Nuclear refueling outages occur at routine intervals and may be included if provided by the plant owner.

  Note: Attachment Y Notices are not included in the set of known planned outages to be assessed in the TPL analysis. Approved Attachment Y Notices for generator suspensions and retirements starting in the Near-Term Transmission Planning Horizon are modeled offline beginning on their start date as described *in Section 3.3.3 of this BPM*.

Protection System Outages

- CROW outage scheduling system – Planned non-redundant protection system outages that are submitted in the MISO Outage Coordination process may be scheduled in the Near-Term Transmission Planning Horizon but most are generally not scheduled beyond the Operating Horizon which does not ensure sufficient coverage for the five-year Near-Term Transmission Planning Horizon.
- MTEP projects that are included in MTEP Appendix A are commitments to build to meet needs in the five-year Near-Term Transmission Planning Horizon. Protection system outages that are required to enable transmission upgrades and new facility construction by the expected in-service date are to be provided by the Transmission Planner to the Planning Coordinator in response to the annual MTEP cycle data request from the Planning Coordinator.

4.3.6.2 Selection of Planned Outages for Inclusion in Planning Assessment

Selected planned outages are provided by the Transmission Planner to be included for study. The outage selection is determined by the Transmission Planner in accordance with the established criteria in the Transmission Planner technical rationale, or alternatively in the MISO technical rationale described herein. This applies to outages occurring in the evaluation time period beginning January 1st of the current MTEP cycle two-year model and ending December 31st of the current MTEP cycle five-year model.

BES Classification

Selection of candidate outages for the TPL assessment is limited to BES facility outages and additionally those non-BES facilities which the Transmission Planner has previously determined to have a significant impact on the BES.

Timing and Duration of the outage

Outage periods are used to establish the timing of the outage event and the appropriate conditions to be studied. Outage periods for scheduled outages will be obtained from the CROW outage records. For outages that are planned but not yet scheduled, estimates of the length of the outage period are made by assigning an outage duration needed for various equipment types and the work required while the completion date can be established from the estimated in-service date of the associated system upgrade or maintenance project.

- Crow schedules determine the outage period for outages scheduled in the MISO Outage Coordination process. These are planned/scheduled facility outages that are expected to occur with start and end times specified in the outage request. Most scheduled outages are planned in the Operating Horizon, but some may extend into the Near-Term Transmission Planning Horizon.
- For planned outages associated with transmission upgrades (including lines, breakers, station upgrades) that have not yet been scheduled, the estimated outage schedule is determined from the in-service date of the related upgrade project. At a minimum, planned outages needed to facilitate all MTEP Appendix A projects in the MISO MOD system that are included in the current MTEP cycle are included for assessment. The Near-Term Transmission Planning Horizon spans a five-year window of time, so the precise outage schedule may not be known but needs to be assumed to consider any overlap of outages that should be assessed simultaneously. The member Transmission Planner will specify the start and end dates using their established methodology if available. Otherwise, the following guideline can be used to determine the default outage period where the outage is planned to meet the in-service date of an upgrade project not yet scheduled.
    - Tx reconductor – Duration of 1 week per mile ending on the in-service date.
    - Tx rebuild – Duration of 2 weeks per mile ending on the in-service date
    - Transformer Replacement – Duration of 2 weeks ending on the in-service date.
    - EHV Station Rebuild – Duration of 10 weeks ending on the in-service date.
    - HV Station Rebuild – Duration of 6 weeks ending on the in-service date.
    - New Substation loop in – Duration of 3 weeks ending on the in-service date.
    - Capacitor Bank/Switch Reactor Installation – Duration of 1 week ending on the in-service date.
    - Line Terminal/Bus upgrade – Duration of 2 weeks per terminal/bus ending on the in-service date
    - Tap Structure installation – Duration of 5 days ending on the in-service date
    - Nuclear unit refuel – Duration determined by the outage period of most recent refueling outage.

Outage concurrency

Since multiple outages may overlap for a given period of time, it is necessary to determine the combined impact from concurrent outages in addition to evaluating the impact of each outage separately. The Transmission Planner will determine which outage combinations should be created for outages with overlapping schedules based on flexibility of rescheduling, lead time, etc. Higher order combinations should be considered for overlapping outages where the outage facilities may have related impacts due to their electrical proximity. Once outage combinations have been established, the combined impact of the outages will determine the need for inclusion in the TPL assessment.

Impact Criteria and Selection Method

The selection process is used to identify those candidate outages that are expected to have a severe impact on the transmission system to produce a limited set of planned outages that are included in the TPL studies. The method for selection is based on prior studies of system impacts of NERC Category P3/P6 contingency events that result in overloading, voltage decline or risk of instability.

Use of the NERC Category P3 and P6 event analysis from prior year TPL assessment results can show where candidate outages in combination with a contingency event would result in non-consequential load loss. If the candidate outage is a member of the P3/P6 contingency pair and the analysis indicates there is risk of non-consequential load loss, then the outage and or outage combination is selected for inclusion in the current year TPL assessment steady state analysis. If the candidate outage is a member of the P3/P6 contingency pair and the analysis indicates a solution failure that is confirmed to be an unstable operating condition (not a numerical instability), then the candidate outage and/or outage combination is selected for inclusion in the current year TPL assessment stability analysis.

4.3.6.3 Analysis of Planned Outages

Selected outages are evaluated for NERC Category P1 contingencies under conditions that are applicable to the period of the outage. The transmission system must remain within applicable facility rating and voltage limits and remain stable with no cascading or uncontrolled islanding and without risk of non-consequential load loss. For steady state analysis and steady state stability analysis, planned outages will be assessed in the MTEP Target A model corresponding with the outage period where the outage end date will determine the selection of the appropriate model period. The shoulder models are used for outages normally occurring in off-peak conditions and summer peak models are used only where the outage is expected in peak loading conditions. For transient stability analysis, the five-year light load dynamic model will be used to assess planned outages corresponding with the five-year study period. Planned outages are simulated as outage event(s) plus the next contingency with system adjustments following the outage event that includes generation redispatch but not load shedding. However, load adjustments may include load shifting or voluntary curtailment of load by a customer to facilitate a planned outage.

4.3.7 Assessment of Long-Lead Equipment Outages Resulting from Spare Equipment Strategy

MISO performs a targeted assessment of long lead transmission outages in accordance with NERC Standard TPL-001-5. Facilities identified by the Transmission Planner where spare equipment does not exist, resulting in long lead times for replacement of equipment are included in steady state and stability analysis. The steady state assessment of long lead equipment outages simulates the prior outage of the equipment in conjunction with P0, P1 and P2 event for all scenarios described in Section 4 of this BPM. Stability assessment of the long lead equipment outages simulates the prior outage of the equipment in conjunction with selected category P1 and P2 contingency events expected to have more severe system impacts for applicable stability scenarios.

If the Transmission Planner's spare equipment strategy does not result in unavailability of major Transmission equipment that has a lead time of one year or more, the Transmission Planner will indicate as such to MISO.

4.3.7.1 Contingency Coordination for Spare Equipment Outages

During each MTEP cycle MISO will solicit for Long Lead Time (LLT) equipment facilities and associated equipment contingencies for both the steady state and dynamic analyses. The Transmission Planner will provide contingencies in accordance with the schedules noted below.

4.3.7.1.1 Steady State Analysis Spare Equipment Outages

MISO will solicit TPs for steady state Long Lead Time (LLT) equipment facilities and associated equipment contingencies each year. The Transmission Planner will provide such contingencies as part of their submission of all other steady state analysis TPL contingency definitions.

4.3.7.1.2 Dynamic Analysis Spare Equipment Outages

MISO will solicit TPs for dynamic Long Lead Time (LLT) equipment facilities and associated equipment contingencies each year. The Transmission Planner will provide such contingencies as part of their submission of all other dynamic analysis TPL contingency definitions.

4.4 Long-term Planning

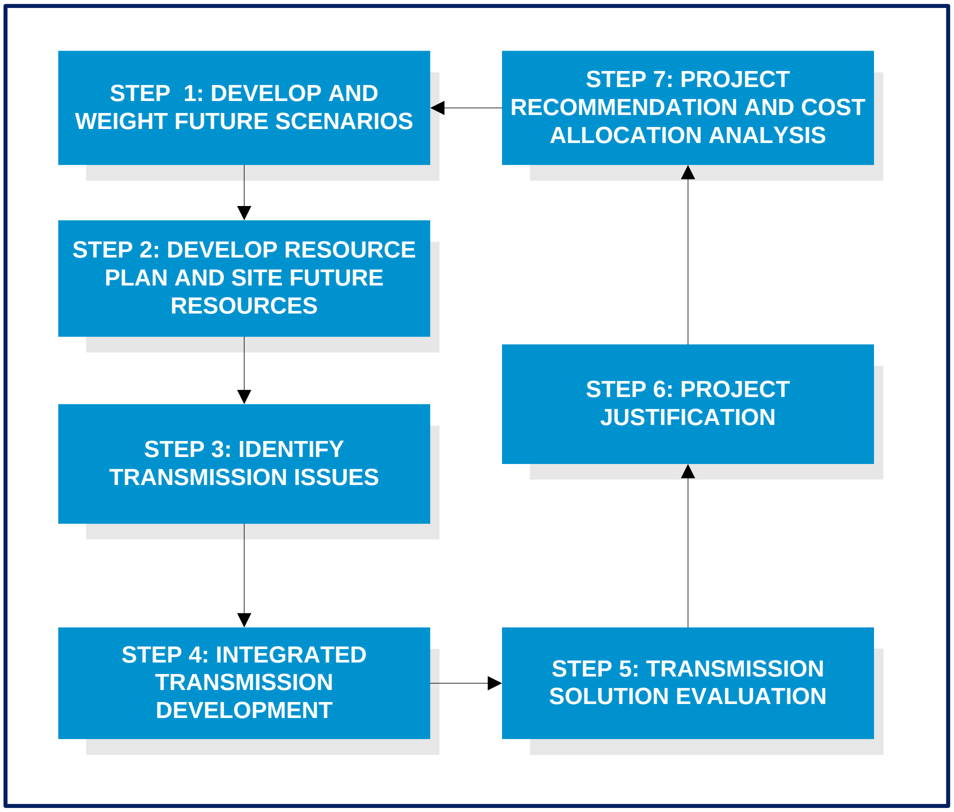
4.4.1 Introduction

The MISO long-term planning process focuses on addressing sub regional, regional, and interregional transmission issues related to historic and future market congestion, long-term economic opportunities and/or public policy compliance in accordance with the provisions of *Section C6 of Attachment FF of the MISO Tariff*. The objective of the long-term planning process more commonly referred to as the MISO Value-Based Planning process is to develop robust transmission solutions to increase long-term value under a wide range of potential conditions that comply with Federal, State, local and transmission owner reliability standards and public policy mandates. To develop robust transmission solutions, the MISO Value Based Planning Process employs a scenario-based approach which considers a range of potential public policies, economic conditions, demand and energy growth rates, fuel prices, as well as other industry trends. Long-term planning is an open and transparent process, compliant with FERC Orders 888, 890 and 1000, which depends upon the collective input of stakeholders and regulators throughout all phases.

4.4.2 Process Steps for Long-term Planning

The MISO Value Based Planning process shown *in Figure 4.4.2-1 below,* and the detailed steps are documented in this subsection. While not all steps of the MISO Value Based Planning process will be accomplished during each MTEP cycle, the determination of which step(s) as well as the timeline will be part of the scoping discussions preceding each MTEP cycle. The following sub-sections provide typical timelines for each step; however, actual study timelines may vary.

Figure 4.4.2-1: Long-term Planning Process Diagram



4.4.2.1 Develop and Weight Future Scenarios

By defining a wide range of plausible futures, MISO ensures reliable and efficient grid operations. Future scenario definitions and uncertainty variables are developed for each MTEP cycle with advisement from the Planning Advisory Committee. The Futures development cycle typically begins in January of the year prior the start of the targeted MTEP cycle (e.g. the development of MTEP17 Futures would begin in January 2016). Barring significant changes in policy and economic drivers, Futures scenario definitions will continue to be used for multiple MTEP cycles. While the intent is to use the Future definitions for up to three consecutive MTEP cycles, uncertainty variables within Futures definitions will be evaluated and may be updated annually for relevant changes to policy and economic drivers (e.g. updating the mid-level Henry Hub natural gas price forecast). The determination for what changes/if any to Future definitions and uncertainty variables will occur at the onset of the Futures development process, and will include advisement from the Planning Advisory Committee. In determining final benefit-cost ratios of transmission projects or portfolios, MISO must also remove undue discrimination or the potentially excessive influence of any given assumption or set of assumptions. With this in mind, MISO will develop and assign weighting to the Futures modeled in each MTEP cycle, which will include advisement from Planning Advisory Committee stakeholder sectors. Weights are typically developed after Future definitions are finalized in the June/July timeframe. Weights will be revisited preceding each MTEP cycle; however, barring a change in future definitions weights may remain unchanged from the previous cycle until exceeding the three-year limit for Futures definitions.

4.4.2.2 Develop Resource Plan and Site Future Resources

4.4.2.2.1.1 Resource Forecasting

The MISO Generation Interconnection Queue provides initial information about the new generation being proposed within the footprint. However, since the Generator Interconnection Queue tends to identify changes within five years or less for new capacity, a resource expansion tool is used to supplement the years beyond that timeframe in order to maintain the load-to-resource balance and Planning Reserve Margin target. Inputs to the resource expansion tool include but are not limited to a) resource requirements driven by regulatory mandates, state laws and/or federal laws (e.g., State Renewable Portfolio Standards, State implementation plans for EPA compliance, etc.), b) other intelligence on new generation projects and long-range integrated resource plans not yet reflected in the MISO Generation Interconnection Queue, and c) specific input from Generation Developers. Regional Resource Forecasting (RRF) plans, using the preceding steps, are developed for each MTEP Future and are typically available for review in the August/September timeframe.

4.4.2.2.2.2 Generation Siting

Once the future generation from the portfolio assessment process is identified, for transmission planning purposes it must be sited at a physical interconnection point within the study models.

For its long-range planning studies, MISO planning staff forecasts likely sites where new generating resources may be developed at the high-voltage bus level and presumes that new interconnecting transmission facilities will be constructed as necessary to support generating plants. A number of sources are used to determine likely locations for new generating units including but not limited to the MISO Generator Interconnection Queue, State Integrated Resource Plans, and public announcements. For future generation not yet specifically identified, MISO planning staff will develop assumptions about the new resources location considering distance to fuel sources, distance to load, land designations (e.g. Class 1 lands), and existing infrastructure among others. MISO also considers identified Renewable Energy Zones when determining potential sites for renewable resources. The combined approach endeavors to provide reasonable assumptions regarding fixed-in-place generation to provide a starting point for integrated system reliability and economic enhancement modeling and analysis. In this process, results from completed power flow modeling are used to provide input data to MISO's production cost model. A study horizon of 20 years is to be utilized for long-term planning evaluations to determine project benefits. The long-term planning evaluation process is structured to ensure robustness by utilizing multiple Futures to analyze future impacts in determining the benefit of system expansion projects. These siting assumptions will be provided for stakeholders review and input.

4.4.2.3 Identify Transmission Issues

A key component of MISO Value Based Planning is the identification of Transmission Issues. In most cases, Transmission Issues include economic value opportunities and public policy compliance issues. Economic value opportunities typically include transmission congestion or other market issues where solutions are desired to eliminate costly generation redispatch. This review identifies specific constraints and data associated with those constraints such as shadow prices, binding hours, and binding levels. Once congestion issues are identified, they will be reviewed and shared with stakeholders for feedback. The identified congestion issues are typically available for stakeholders review in December/ January timeframe.

In addition to congestion issues, other types of economic issues, reliability issues and public policy issues may also be considered in the MISO Value Based Planning process. Public policy issues are typically derived from federal, state, and local laws and mandates that govern the maximum or minimum amount of energy or capacity that can be generated by specific types of resources. Also, other economic benefits, such as transmission loss reductions, planning reserve reductions, or the release of "trapped" capacity may be considered in the MISO Value Based Planning process.

4.4.2.4 Integrated Transmission Development

After Transmission Issues are identified, stakeholders will be given the opportunity to submit solutions to these issues. The solution submission window typically opens in January/February timeframe and lasts for six to eight weeks. 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 will continue to work with stakeholders to ensure solutions properly address the Transmission Issues.

4.4.2.5 Transmission Solution Evaluation

The first step in transmission solution development is to convert various solution ideas into proposed projects. Because an integrated transmission plan may consist of multiple non-contiguous facilities to address market congestion or public policy, a determination must be made on how collections of transmission facilities may be combined and tested through an iterative process to compose a project or portfolio. Transmission Issues will be evaluated to determine whether they are decoupled or coupled with each other. Isolated, decoupled issues do not impact others whereas coupled issues represent a group of related regional issues. Solutions to decoupled issues can be evaluated independently as alternatives. Solutions to coupled issues will be evaluated as a collection of facilities to ensure the effectiveness of the transmission plan.

Detailed reliability analysis is required to identify additional issues that may be introduced by the transmission plans developed through economic assessment. Long-term transmission plans may need to be adjusted to ensure system reliability. Reliability analyses will address NERC standards and local planning criteria and may include, but are not limited to, powerflow, transient and voltage stability, and short circuit. Additionally, the reliability assessment determines the reliability-based value contribution of the long-term transmission plans. As value-driven regional expansions are justified, traditionally developed intermediate-term reliability plans may be affected. The combined impact of both reliability and value-based planning strategies must be fully understood in order to further the development of an integrated transmission plan.

Transmission solution evaluation is an iterative process that can take several months to several years to produce an integrated transmission plan. It is necessary that the transmission plan is developed to be effective under the range of Futures studied. Therefore, the proposed transmission plan will be tested under each of the agreed upon Future for economic results (e.g., benefit-to-cost ratios, etc.), reliability performance (e.g., NERC standards, etc.), and public policy performance (e.g., compliance with RPS mandates, etc.). To ensure sufficient coordination with Generation Interconnection, MISO will review all network upgrade facilities that may be identified in ongoing Generation Interconnection studies for impacts on identified system constraints and economic project benefit calculations. Additional sensitivities may also be evaluated such as location and replacement of Regional Resource Forecast (RRF) generation. To the extent issues are uncovered such as reliability violation, incremental congestion, etc., additional adjustments may be needed to the overall transmission plan.

It is important to note that when looking beyond the NERC TPL long-term planning horizon (10 years), it is not necessary that a long-term plan resolve all reliability issues, but to the extent the specific integrated transmission plan causes or aggravates major reliability compliance issues, the MISO Value Based Planning process must work to address such issues through additional projects, project scope changes, or removed projects and evaluate once again pertinent metrics to ensure the best possible plan is developed. In addition, should an economic project inadvertently cause public policy compliance issues such as the inability to meet State Renewable Portfolio Standards, the same type of adjustments and re-evaluation of planning metrics will need to take place.

4.4.2.6 Project Justification

A business case will be created for all projects including an analysis of benefits and costs. Detailed rules on project criteria, benefit metrics and cost determination are provided *in Section 7 of this BPM*.

4.4.2.7 Project Recommendation

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 will be only for those projects that have been shown to meet or exceed all criteria for type of project being recommended. Projects meeting or exceeding all project type criteria will be recommended to the MISO Board of Directors in the last quarter of each MTEP cycle, or as otherwise defined in the MISO Tariff. After Board approval, MISO will determine if any of the qualified projects and facilities to proceed to the developer selection process *in accordance with Attachment FF Section 8 of the Tariff and BPM 027 – Competitive Transmission Process*. Incumbent Transmission Owners have an obligation to put forth a good faith effort to construct facilities which do not go through developer selection.

Eligibility for regional cost allocation will be determined for each recommended project pursuant to the rules *in Section 7 of this BPM as well as Section III.A.2 of Attachment FF of the MISO Tariff*.

4.4.3 Data Sources and Assumptions for Long-term Planning Models

Long-term planning models require a detailed transmission topology, generation operating characteristics, as well as economic parameters. MISO, with advisement from the PAC, will determine variable input assumptions using the latest and most appropriate public data sources. The vendor data may be modified in whole or in part with newer or more appropriate data as desired.

The sources of the data provided by the vendor are:

- Federal Energy Regulatory Commission (FERC) Forms 1, 714
- Energy Information Agency Forms (860, 867, 411, 412, 423)
- North American Electric Standards Board (NAESB)

- North American Electric Reliability Council (NERC) Electric Supply and Demand (ES&D) reports
- Generating Availability Data Systems (GADS) Data
- Environmental Protection Agency (CEMS data)
- ISO, OASIS web sites
- Energy company web sites
- State IRPs
- Base MTEP input assumptions will be determined during the MTEP Futures development process as discussed *in Section 4.4.2.1 of this BPM*.

4.5 Other Cyclical Planning Activities

4.5.1 Baseline Load Deliverability

MISO performs Loss-of-Load Expectation (LOLE) studies primarily within the MTEP context as a "Load Deliverability" study. This study is complimentary to the Baseline Generator Deliverability test discussed below.

- The objective of the MTEP Load Deliverability test is to investigate whether MISO aggregate system and identified Local Resource Zones within the MISO Reliability Authority footprint have sufficient Planning Resources to meet the LOLE reliability criteria identified *in Section 3.5.2 of the Resource Adequacy BPM*[27].

Where the Local Clearing Requirement is greater than the zonal Coincident Peak Demand forecast plus its Planning Reserve Margin and transmission losses and a study is requested by the impacted LSE(s), or applicable regulatory authorities, MISO will evaluate Network Upgrade impacts on limits.

The identified Network Upgrade(s) will be included in the MTEP when a Market Participant or group of Market Participants or other entities agrees to fund the upgrade. The implementation of such a project will be consistent with the Market Participant Funded Projects process, Section 6.1 of this BPM, Other projects consistent *with Section 2.4.1.4 of this BPM*, or other applicable tariff provisions and business practices.

4.5.2 Baseline Generator Deliverability

The Generator Deliverability analysis determines the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints, i.e., without

[27] BPM-011 - Resource Adequacy

being bottled-up. This test is performed as part of the generator interconnection study process on new generators before granting Network Resource (NR) status. The generator is required to fix any transmission constraints limiting deliverability, in order to be treated as a Network Resource. A generator that is certified deliverable, not bottled-up, would be considered deliverable to Load under Module E-1 – Resource Adequacy, of the Tariff.

The deliverability levels of already designated Network Resources may deteriorate over time as a result of Load growth and other changes to the Transmission System. A Baseline Generation Deliverability Study is performed in order to identify and address any new transmission constraints to ensure ongoing deliverability of Network Resources. Also, baseline generator deliverability upgrades represents a reliability need to ensure the continued ability to count on Network Resources nominated to meet reserves.

The Baseline Generator Deliverability analysis is performed using a Summer Peak model and by applying single transmission contingencies to deliverability dispatch patterns. The general generator deliverability study assumptions, as described *under Section 6.1.1.1.9 of BPM-015 – Generation Interconnection*, will be used for the analysis. The generator deliverability will be tested only up to the granted Network Resource levels of the Network Resource units.

4.5.3 Long-term Transmission Rights Feasibility Review

4.5.3.1 Introduction

Auction Revenue Rights (ARRs) are financial instruments that entitle their holders to a share of the revenue generated in the annual Financial Transmission Right (FTR) auction. ARRs are initially allocated to Market Participants based on firm historical usage of the transmission network. Incremental ARRs may be allocated for network upgrades, new and replacement of Network Resources.

Long Term Transmission Rights (LTTRs) are a type of ARRs allocated in Stage 1A or allocated in restoration of the Annual ARR Allocation process that is associated to historical base Load usage of the Transmission System. LTTRs are:

- Allocated in Stage 1A of the ARR allocation.
- Allocated to Market Participants derived from firm historical base Load usage of the Transmission System.
- Guarantee Market participants maintain their previous year LTTR allocated MW amount to the extent it is requested.

- Entitle the holder to a share of the FTR Auction revenue in the form of a stream of revenues or charges based on the clearing price of the ARR path.

The four characteristics of ARRs pertinent to the LTTR include:

- A MW quantity
- A path that is specified in terms of a source and sink. The source may originate from a generation Node, Hub, Load Zone or interface. The sink is always associated with an ARR zone, which is a Hub-type Node. ARR zones are electrical areas defined for the purpose of allocating ARRs based upon locations where a Market Participant serves Load.
- ARR Term (Start and end dates)
- ARR Period (Peak / Off-peak)

ARRs will be allocated once a year, for eight different periods:

- Four Seasons
  - Summer: June, July, August
  - Fall: September, October, November
  - Winter: December, January, February
  - Spring: March, April, May
- Peak and Off-peak Loads

Detailed explanation of FTRs and ARRs can be found *in BPM-004 – Financial Transmission Rights and Auction Revenue Rights.*

This section of the BPM provides the Business practices that incorporate the feasibility of Long–term ARRs into the transmission expansion planning process beginning with the first MTEP annual cycle following completion of the initial establishment of Long-term ARRs.

4.5.3.2 Procedures for Integration of LTTR Feasibility Considerations into the MTEP Process

Both the ARR Allocation process and MTEP Planning process together, should provide to the greatest extent practical, that financial obligations are met in the most economic manner to ensure the feasibility of LTTRs. This may require a repetitive analysis between the ARR allocation process, the FTR Annual Auction (composed of four seasonal cases in both peak and off-peak periods), and the MTEP Planning process due to differences in modeling. The LTTR feasibility study determines the by path cost associated with all LTTR being awarded fully. Transmission

System Flowgates limit the ARR allocations. MISO planning staff will use MTEP near-term, intermediate-term and long-term models to determine the benefit of future system improvement projects to alleviate congestion at each of the identified Flowgates. If a future project does alleviate Flowgate congestion, the project will be included in the SFT model to determine improved ARR allocation. It is required that the MTEP process promote the approval and installation of future system transmission improvement projects to ensure the feasibility of first year LTTR allocations into the future. The MTEP process will also assist to explore the economic benefit of an expanding future LTTR market.

4.5.3.2.1 Information Exchange between the ARR Allocation Process and the MTEP Planning

In order to ensure adequate integration of the ARR Allocation and MTEP Planning processes, an information exchange loop will be established between the FTR, Pricing Administration group and MISO planning staff. The following information will be provided to the FTR Market Administration by MISO planning staff in January of each year for their Annual ARR Allocation scheduled in March:

- The list of transmission projects in Appendix A (recommended by Transmission Provider Board) planned to be in service by the next ARR / LTTR allocation period.
- The list of Appendix A and Appendix B transmission upgrade projects proposed for the five-year horizon, and their service dates.

The following information will be provided to the MISO planning staff in April by the FTR Market Administration group at the conclusion of their Annual ARR Allocation:

- A list of curtailed LTTRs in each of the eight allocation cases.
- A list of planned transmission outages included in the ARR Allocation studies, and identification of any planned outages that cause infeasibility
- A list of binding constraints causing LTTR curtailment and the uplift cost associated with fully funding their feasibility.

4.5.3.2.2 Consideration of Problematic Planned Outages in the Planning Process

Planned transmission outages are not generally considered in the MTEP models, since MTEP addresses the five to 10 year planning horizon. This planning horizon extends well beyond the near-term time frame of planned outages. Annual ARR Allocation incorporates planned outages occurring during the study season and lasting at least seven days. To understand the extent to which the planned outage of certain facilities may be critical to ARR feasibility, a list of any planned transmission outages included in the ARR Allocation cases that can be attributed to infeasibility will be provided to the MISO Expansion Planning staff. These transmission outages will be correlated with planned outages evaluated in the MTEP process to determine if there are mitigating solutions that can be applied to theses planned outage conditions in future allocations to eliminate binding. Such mitigations may include planned upgrades from the planning process, or redispatch/reconfiguration options that can be applied in the allocation models.

4.5.3.2.3 Comparison of LTTR allocation binding constraints with Historical or Planning Model Constraints

When an LTTR is determined infeasible in the allocation, the binding constraints causing infeasibility will be reviewed with the MISO planning staff to determine if the constraint is one that has occurred historically in real time or is projected to occur in planning models. To the extent that the constraint is associated with one appearing in the planning analyses, it is likely that an upgrade has already been identified that will alleviate the constraint. If there is an associated upgrade in MTEP, a review will be made to see if and at what cost the upgrade could be advanced. If no such upgrade has been identified, a review will be conducted to see in what future year a related upgrade may be required as a BRP, and what the cost to advance would be. Finally, if no related constraint can be identified and no future upgrade can be foreseen in the planning models, or can be identified based on existing tariff provisions, the FTR Market Administration group will attempt to determine the cause of the infeasibility in the LTTR allocation process.

4.5.3.3 The ARR Allocation and MTEP Planning Integrated Processes

The combined integrated processes of ARR Allocation and MTEP Planning ensure the optimum economic feasibility of LTTRs into future years, as long as the LTTRs continue to be requested. *Figure 4.5.3.3.1-1 below,* provides a guide to these combined integrated processes. The first year ARR/LTTR allocation will determine the allocation of feasible LTTRs. *Figure 4.5.3.3.1-1 below*, is applicable to the second and subsequent year allocations.

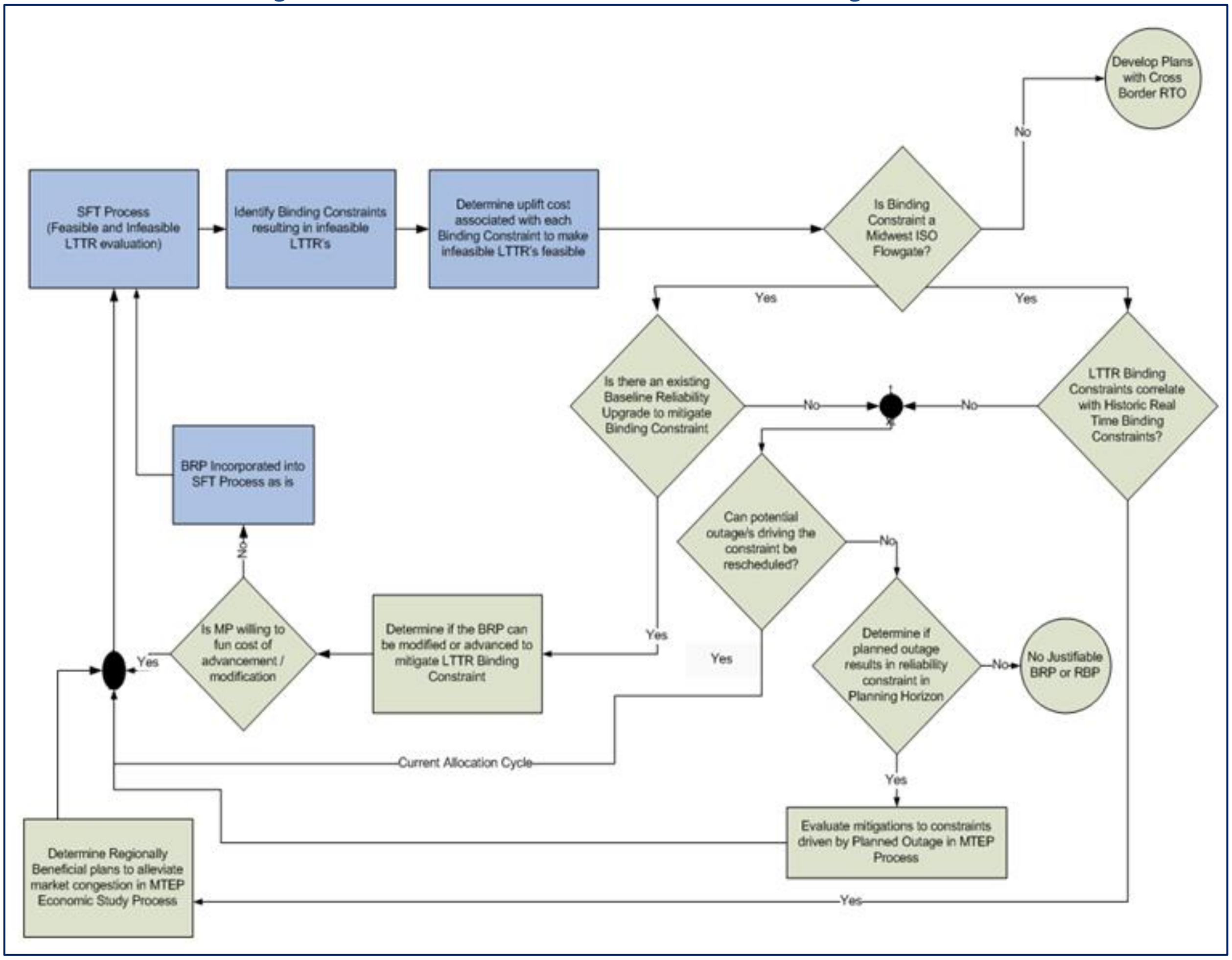
4.5.3.3.1 ARR Allocation Process - First Year LTTR Allocations

The FTR Market Administration Group will use the SFT to determine the first-year allocation of ARRs/LTTRs. All allocated LTTRs in the first year will be feasible. Factors that limit the LTTR allocations include congestion at Transmission System Flowgates and planned outages. The following information will be provided to the MISO Expansion Planning staff by the FTR Market Administration group at the conclusion of their annual ARR / LTTR allocation:

- A list of curtailed LTTRs in each of the eight allocation cases (i.e., Summer peak and off-peak, Fall peak and off-peak, etc.)
- A list of planned transmission outages included in the ARR allocation studies, and identification of any planned outages that cause infeasibility.

- A list of binding constraints causing LTTR curtailment and the uplift cost associated with fully funding their feasibility. The list of binding constraints should be prioritized to identify the most to the least binding constraint on the allocation.

Figure 4.5.3.3.1-1: AAR Allocation/MTEP Planning Process



4.5.3.3.2 ARR Allocation Process - The Second and Subsequent Year Allocations and Infeasible LTTRs

Every ARR allocated in Stage 1A or Restoration becomes a LTTR. LTTRs have rollover rights, i.e., any LTTRs allocated the first year are guaranteed to be allocated in the second and subsequent years, as long as it is requested. This is true even if the LTTR request is deemed infeasible in next year's ARR allocation. The Restoration stage attempts to allocate a subset of the Stage 1A nominations that had to be curtailed to protect feasibility. In order to restore curtailed nominations, the Restoration Process will assign counter flow ARRs to some Market Participants.

All allocated LTTRs were at some point found to be feasible. LTTR infeasibility will be caused by changes in the ARR allocation cases from one year to the next. Such changes include:

- Network and commercial model updates, including topology changes and model corrections.
- Network topology changes due to the set of planned transmission outages considered in the ARR allocation cases. (Outages with a duration of seven (7) or more Days are included in the allocation cases).
- Changes in loop flow and carved-out assumptions.
- Variation in the nomination patterns:
  - A market participant may choose not to re-nominate existing LTTRs which may cause infeasibility of other LTTRs. This is partly addressed by the fact that all existing LTTRs are eligible for counter flow assignment starting year two of the ARR allocation. However, counter flow will only be assigned to achieve feasibility of eligible base ARR entitlements.
  - Since LTTRs are not treated in the allocation process differently from non-guaranteed nominations, Stage 1A requests that did not exist in the previous allocation may cause the curtailment of LTTRs.
- Expiration of existing rights:
  - Termination of Point-to-Point services or retirement of generating units may lead to the termination of ARR Entitlements and associated LTTRs. This may cause infeasibility, as the terminated LTTRs may provide counter flow to other LTTRs.

The feasibility of the set of outstanding ARRs is required in order to ensure that sufficient FTR Auction revenue is collected to fund ARRs. Since infeasible LTTRs may not be funded from the FTR Auction revenue, their cost is distributed across all LTTR holders, in their LTTR MW share ratio.

Prior to future year's ARRs/LTTRs allocation, the FTR Market Administration Group will update the SFT model with the appropriate MTEP projects applicable to the allocation year. The SFT analysis will determine the feasible LTTRs that can be allocated subject to Flowgate constraint. Impact of planned outages will be considered in the SFT analysis. The MISO planning staff can work with the FTR Market Administration Group with near-term planning MTEP models to assess the impact of planned outages on MISO Flowgates, assess the benefit of rescheduling outages and/or re-dispatch to alleviate the Flowgate congestion. This combined effort between the two groups will provide possible updates to the SFT to ensure the optimum allocation of ARRs/LTTRs.

4.5.3.3.3 MTEP Process - The Second and Subsequent Year Planning Models

As indicated *in Figure 4.5.3.3.1-1*, the MISO planning staff will use the various MTEP models to evaluate Flowgate constraints.

4.5.3.3.3.1 Near-term Planning / 1-2 Year Planning Horizon

As previously mentioned, the MISO planning staff can work with FTR Market Administration Group during the study year SFT analysis to address planned outages/re-dispatch to alleviate Flowgate congestion.

4.5.3.3.3.2 Intermediate-term Planning / 1-10 Year Planning Horizon and Long-term Planning Horizon / 1-20 Year Planning Horizon

MISO planning staff can identify existing MTEP projects or work with the appropriate Transmission Owner to develop future projects required to alleviate Flowgate congestion under MISO control. This will be necessary in the second and subsequent years to ensure the feasibility of first year allocated LTTRs. Regarding Flowgates that are not within MISO control, MISO will need to develop plans with other RTOs as required.

The MISO planning staff will correlate LTTR binding Flowgates with real-time congestion hours. If there is no correlation, there is not likely to be a Market Efficiency Project solution to the LTTR binding constraint.

If there is correlation of LTTR binders with real-time congestion hours, there may be a MEP solution that would resolve the LTTR binding constraints. In this case, the binding Flowgates will be included in the annual process to evaluate the most congested Flowgates. An existing MEP may be modified to include the LTTR related economic benefits or a new MEP project can be developed to alleviate Flowgate congestion. MEPs can be advanced through the MTEP Process based on the project’s economic merits. Reliability Based Projects will also need to be evaluated, relative to the LTTR economic related benefits at a Flowgate, to assess if the project’s in-service date can be justifiably advanced in the MTEP process. To the extent that a proposed upgrade is an alternative solution to an otherwise identified system issue causing the need for a BRP or a MEP, and such an alternative upgrade would also result in a reduction in the amount of infeasible LTTR cost distribution that is required, such reduction in cost distribution will be considered in the economic comparison of alternatives to the BRP or MEP.

Intermediate-term and long-term BRP and MEP projects would be identified and included in the SFT model in the appropriate year as determined by the project in-service date.

4.6 Interregional Participation

MISO planning staff coordinates transmission expansion studies with adjacent, interconnected transmission providers, Regional Entities, and RTOs. MISO has coordination agreements in place with the PJM RTO (MISO-PJM Coordinated System Plan), Southwest Power Pool (SPP), and Tennessee Valley Authority (TVA). The coordinated agreements call for Coordinated System Plans (CSP) with the other regional planning entities. The primary purpose of these CSPs is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties.

To accomplish this purpose, the CSP will:

- Integrate the Parties' respective transmission plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and Network Upgrades that were considered.
- Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or Network Upgrades; and
- Describe results of the joint transmission analyses for the combined transmission systems, as well as the procedures, methodologies, and Business rules utilized in preparing and completing the analyses.

The Inter-regional Planning Stakeholder Advisory Committee (IPSAC), which consists of stakeholder and the planning staff of MISO and other neighboring planning regions, will meet at scheduled times to discuss planning issues, concerns, and activities related to CSPs. The IPSAC also exchanges data regarding planning model assumptions for system performance, interface expansions, and network contingencies. The meeting notifications, schedules, and materials of IPSAC meetings are communicated to the stakeholders via Planning Sub-committee and Planning Advisory Committee email exploder lists.

4.7 Dispute Resolution

Disputes involving proposed expansion planning projects are resolved in accordance with Attachment HH (Dispute Resolution Procedures) of MISO's FERC Electric Tariff. Attachment HH includes provisions for dispute resolution through progressive steps consisting of informal negotiation, mediation, and arbitration. It also includes provisions for the formation of MISO's Alternate Dispute Resolution Committee, along with procedures for Expedited Dispute Resolution.

The dispute resolution process begins with a disputing party informing MISO of the subject of a dispute, and designating a representative for further contact. MISO's Client Relations Representative will attempt to resolve the issue with the disputant's representative. If the dispute cannot be resolved at this level, the disputing party notifies MISO and identifies a company officer authorized for further negotiation. MISO likewise designates a company officer, and the two officers attempt to resolve the dispute through informal negotiation.

In the event that the companies' officers cannot resolve the dispute, the matter is presented to the Alternative Dispute Resolution Committee. This Committee (described below) determines if the matter is sent to mediation or arbitration. For mediation, the disputing parties first agree upon a mediator. The mediator meets with the disputants, where each party may present written statements of issues and positions. The mediator evaluates the parties' statements, and provides written, non-binding recommendations to resolve the dispute.

For arbitration, the disputing parties may agree upon a single arbitrator, or a panel of three arbitrators may be selected according to the procedures of Attachment HH. The arbitrators are authorized to hold evidentiary hearings, if needed, as part of a process to discover relevant facts. The arbitrator(s) issue a written decision based on the evidence in the record, the applicable MISO Agreement or Tariff, applicable state and federal standards, and relevant decisions made in prior arbitration proceedings. The decision of the arbitrator(s) is binding, subject to applicable state and federal laws and approvals.

The Alternative Dispute Resolution Committee consists of six representatives selected by the Transmission Provider Board. The Committee is intended to reflect the diversity of MISO, so that Committee members are selected according to the size, type, and geographic location of Owners and Members. No more than one Member on the Committee may be a representative of the same Owner or Member. Among its responsibilities, the Committee is charged with identifying and maintaining a pool of qualified individuals to serve as mediators or arbitrators.

Expedited Dispute Resolution procedures may be applied in disputes involving real-time operation (affecting system security or reliability) or available transmission capacity determinations. Disputes are resolved according to the system described in the preceding text, but disputants proceed through the process on an expedited schedule. In some cases, specific MISO officer positions have authority (from Attachment HH) to negotiate disputes under expedited conditions.

5 Long-term Transmission Service Requests

5.1 Introduction

Requests for transmission service must be evaluated for impacts on system reliability. MISO planning staff is responsible for evaluation of long-term firm transmission service requests with reservation periods of one year or longer, which will be referred to as requests in the planning time horizon. The evaluation process is initiated when a transmission customer submits a qualifying request on MISO OASIS. Certain requests for firm transmission service require power flow network analyses in addition to a flow-based analysis, in order to evaluate the system's ability to accommodate the request. The Tariff and other MISO documents identify the procedural requirement of the transmission service reservation process. This document provides information to be used in the performance of network analyses of requests for firm transmission service under the Tariff by MISO, or others performing such analyses on behalf of MISO. Studies may be performed directly by MISO planning staff or may be performed by others on behalf of MISO under MISO guidance. In all cases, MISO is responsible for the final study results and conclusions and will have decisional control over the transmission service process.

5.2 Triage

Whenever a long-term transmission service request is submitted on OASIS, Tariff Administrators put the request in "Study" mode which indicates MISO planning staff will further review the request. MISO planning staff runs a daily query that imports the Study TSRs from OASIS and then starts processing them based on queue priority. MISO planning staff then takes appropriate steps to process the transmission service requests based on the type of request as described below.

5.2.1 Processing of "Renewal" Transmission Service Request

MISO planning staff does not restudy renewal transmission service requests. Upon receiving such requests, the MISO planning staff will verify and ensure that the parameters of the renewal TSR matches the parameters of the parent TSR and meet the FERC Order 890 rollover reform requirements as posted on MISO OASIS. The renewal TSR must start immediately following the expiration of the parent TSR. If the renewal meets these requirements, MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within fifteen (15) Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the TSR on OASIS. If MISO receives the specification sheets, then the TSR will be accepted and the customer shall have fifteen (15) Days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that fifteen (15) day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.2 Processing of "Redirect" Transmission Service Request

Upon receiving the redirect request for a particular transmission service request, the TSR group engineers perform MUST (Managing and Utilizing System Transmission) analysis to determine the distribution factors of the new path on the constraints identified in the original request analysis and all the constraints with the new redirected path. If the path has a greater than three (>3%) percent impact on the OTDF or greater than five (>5%) percent impact on the PTDF, then the request for redirect transmission service is denied. If the impact on old constraints and new constraints is less than or equal to the thresholds mentioned above, then the redirect request is accepted. The intent of this check is to ensure that the impact of the redirected path, on any flow gate, is not greater than the original path's impact on the flow gates identified when the original TSR was studied.

If the redirect request meets these requirements, the MISO planning staff will request the submittal of two copies of the Specification Sheets which are due within fifteen (15) Calendar Days after MISO makes the request by posting comments on OASIS. If MISO does not receive the specification sheets by the posted due date, MISO will refuse the redirect TSR on OASIS. If MISO receives the specification sheets, then the redirect TSR will be accepted and the customer shall have fifteen (15) Days to confirm the TSR on MISO OASIS. After MISO accepts the TSR, it triggers an automatic timer on MISO OASIS for that particular TSR and customer's failure to confirm the TSR within that fifteen (15) day period will result in an automatic refusal of the TSR, also referred to as "Retracted."

5.2.3 Processing of "Original" Transmission Service Request

When the customer submits an original long-term transmission service request, MISO engineers determine if a System Impact Study (SIS) is required. MISO will determine whether an SIS is required by reviewing the type of request, the duration of the requested TSR and the flow based analysis results. If the start and end times of the requested transmission service are beyond eighteen (18) Months of the queued date then an SIS is required. If the start and end times of the requested transmission service both fall within eighteen (18) Months of the queued date, then it is up to the discretion of MISO to decide if an SIS is required. If the OASIS Automation tool results indicate significant constraints, which in the engineer's judgment cannot be mitigated during the requested service period, then the request will be refused or counter-offered for a period with no constraints.

If the source for the requested NITS TSR is a MISO aggregate deliverable resource, as identified during the Generation Interconnection NRIS deliverability study or through a market transition deliverability test as a result of a Transmission Owner integration, then the request can be accepted without further analysis for the aggregate deliverable amount. Any incremental MW request above the aggregate deliverable MW amount shall require an SIS.

5.2.4 Application of Rollover Rights for Long-term Firm Service

5.2.4.1 General Principles

Firm transmission service customers with contracts have the right to rollover their service provided the service and the request to roll it over conform to the provisions of *Section 2.2* of the tariff.

5.2.4.2 Original Requests

When a customer requests long-term firm transmission service MISO will evaluate the request for periods beyond the stop date of the request to determine if rollover rights will be available for future periods based on existing firm commitments. If this evaluation determines that sufficient capacity is unavailable to accommodate the request for potential future rollover periods, the Service Agreement will stipulate that the customer will not be permitted to rollover its service beyond the period where sufficient capacity exists. However, the customer has an option to make network upgrades provided it agrees to fund the direct assigned network upgrades, as identified during the Facility Study process, to ensure there is sufficient transmission capacity up until the stop date or beyond the stop date of the TSR.

5.2.4.3 Subsequent Requests

In considering subsequent requests for long-term firm service, MISO will not remove capacity associated with a potential rollover from its OASIS. When evaluating the subsequent requests, MISO will assume that rollover rights will be exercised by all prior confirmed requests that are eligible for rollover rights.

If the new request cannot be accommodated, the new customer will have the option of proceeding with an SIS to determine any upgrades necessary to accommodate the request under the assumption that prior confirmed service will be rolled over.

5.2.4.4 Evaluation or Requests Out of Queue Order

Situations exist where a TSR is analyzed before a higher queue priority competing request if the two requests cover different reservation periods and study time constraints are an issue – i.e., the lower queue request is to start before the higher queue request and not enough time exists to study the requests in queue priority. An example is if two requests are received, and transmission capacity is available for each request in their respective time period but not available for both transactions to occur simultaneously in subsequent time periods.

5.3 System Impact Study (SIS) Process

After MISO has made the determination that an SIS is required during the Triage process, MISO starts the SIS process with a few administrative steps outlined below.

5.3.1 System Impact Study Agreement (SISA)

5.3.1.1 Step 1 of SISA

In the first step MISO will send the Transmission Customer an SISA within thirty (30) Days of receiving the request on OASIS. The SISA will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies in the queue, and whether certain studies can be done in parallel with each other. The starting study deposit for a typical SIS is $20,000 which is refundable if there are any unused balances after the study is complete. For multi-party studies, the cost of performing study will be distributed proportionately for the group study based on the MW size of each TSR in the group.

5.3.1.2 Step 2 of SISA

In the second step the Transmission Customer is required to execute and send the SISA back to MISO within fifteen (15) Days after MISO initiates the SISA request. The executed SISA must include the initial $20,000 deposit for the study. If MISO does not receive the SISA and the study deposit within fifteen (15) Days from the time MISO makes that request, MISO shall refuse the TSR on OASIS. If the fifteenth (15th) day happens to be either on a weekend or a holiday, then MISO engineers will use 10AM of the next first (1st) Business Day as the deadline to accept the SISA.

5.3.1.3 Step 3 of SISA

In the third and final step, if MISO receives the SISA within fifteen (15) days, then MISO will start the SIS and complete the study within sixty (60) Days from the time the agreement and deposit are received by MISO as defined by Attachment J of the Tariff.

5.3.2 System Impact Study, Technical Overview

Once the customer sends the SISA and the study deposit, MISO starts the actual SIS. Depending on the duration of the Transmission Service request, whether it is a one (1) year request or starting after the first eighteen (18) Months after the queued date, the MISO planning staff will utilize OASIS Automation and off-line network analysis evaluation as appropriate.

5.3.2.1 Flow/Interface Limit Based Analysis

The OASIS Automation tool is a flow-based analysis tool that is used to evaluate the impact of the requested transfer on all MISO Flowgates. The tool identifies Available Flowgate Capacity (AFC) on all MISO Flowgates with the impact of the requested transmission service for the next 18 Months. All long-term transmission service requests with stop dates within eighteen (18) Months of the queue date are evaluated using the OASIS Automation tool to ensure that there is enough capacity available during the 18 Month AFC window. While evaluating TSRs using the OASIS automation tool, MISO uses the queue date of the TSR as the first day for the AFC verification for the next 18 Months.

- If the start date and the end date of the TSR are within the next eighteen (18) Months of the queued date, then the OASIS Automation tool results are sufficient to either accept or refuse a TSR, unless MISO planning staff believes that further analysis is required and an offline analysis is warranted.
- If the start and end date of the TSR are beyond eighteen (18) Months of the queued date, then MISO does not use the OASIS Automation tool results. In such scenarios, MISO will rely on the offline analysis only.
- If the start date of the TSR is within the next eighteen (18) Months of the queued date and the end date is beyond the next eighteen (18) Months of the queued date, MISO uses the OASIS Automation tool and the offline analysis.
- If the results of the OASIS Automation tool indicate that there is no capacity available on any MISO Flowgate, then MISO will take appropriate action depending on the term of the requested transmission service as mentioned below.
  - If the start date and the end date of the TSR is within the next eighteen (18) Months of the queued date, and there are negative AFCs on any Flowgate, then MISO will refuse the transmission service.
  - If the start date of the TSR is within the next eighteen (18) Months and the end date is beyond the next 18 Months, then MISO will defer the start date of the TSR until there are no negative AFCs. The offline analysis is required to assess system availability beyond 18 Months. All other associated Module B BPM requirements still apply such that the minimum term of the TSR must be in the increments of one year.

In addition to flow-based limits, there can be interface limits for selling transmission services to or from certain interfaces. Any such interface limits are posted on the MISO OASIS.

Such a limit can be for:

- Exporting to a specific POD or Importing from a specific POR;
- Exporting to a group of PODs or importing from a group of PORs

The effective interface limits will be posted on MISO OASIS under OASIS Notices in the following document: *MISO_Subregional_Interface_Limit.pdf*.

5.3.2.2 Network Analysis Concepts

5.3.2.2.1 Model Development

An offline network analysis is used to model the requested transmission service, and the subsequent rollover rights, to determine whether the power can be transferred on the requested path without reliability concerns. Up to three study models may be developed depending on the start and stop dates of the requested service. MISO planning staff will determine the number of models required in consultation with the Ad Hoc Study Group established by MISO planning staff pursuant *to Section 5.5.1 of this BPM*.

The first model is developed to simulate the forecasted summer peak conditions within the next eighteen (18) Months of the start date of the TSR and is called the near-term case.

The second model is developed to simulate conditions during the rollover period of the request, typically five years and beyond, from the start date of the TSR and is called the out-year case.

A third model may be developed to examine other system conditions (off-peak summer conditions, peak winter conditions, etc.) if it is determined by MISO planning staff that the results of this analysis would be beneficial to the TSR analysis. Items that MISO planning staff may consider when determining if a third model would provide sufficient value to justify development include: (To be determined based on input from affected Transmission Owner(s) or the customer).

The base cases for the near term and out year cases are built using the Model on Demand (MOD) base case that is updated on a Monthly basis by the Model Engineering group. MISO planning staff makes several changes to this case to ensure that the case represents the most accurate topology expected to occur during peak conditions, for the near term and out year scenarios. All changes that are modeled in the cases are outlined below:

- All previously queued Original and Renewal TSRs that have a status of Study, Accepted, or Confirmed are modeled in the base cases.
- All MTEP Appendix A projects that are expected to be in service should be included in each of the models that will be utilized for the study.
- All generator interconnection related transmission upgrades that have gone through the MISO queue process and have a signed GIA.
- Remove known counter flow transactions
- Extend existing rollover right transactions—applicable to long-term transactions
- Near term and out year models are built using MISO collaborative series summer Bus, Load, and generator profiles from the Model on Demand (MOD).
- Planning models will be populated with applicable ratings for system intact and contingent conditions. These ratings are developed per FAC-008 and submitted to the MOD tool for existing and future facilities. Normal ratings are the applicable ratings for system intact conditions and emergency ratings are the applicable ratings for contingent conditions. When producing power flow models from MOD, Rate A will be populated with the normal rating from MOD and rate B will be populated with the emergency rating from MOD for the appropriate seasons.

MISO does not model the following information in their study cases for the evaluation of long-term transmission Service requests:

- Short-Term Transmission Service requests (Less than one year)
- Redirected capacity of confirmed Transmission Service Requests (capacity of original request will be modeled). The reason for not modeling redirected paths is because currently the redirect paths do not have rollover rights. If NAESB approves rollovers for redirect requests, MISO will make appropriate changes to the modeling assumptions.
- Preempted Reservations - Network analysis is performed for firm requests only. Before performing analysis for firm requests, non-firm reservations and any preempted firm transactions identified by the Tariff Administrator necessary for OASIS Automation to accept the request will be removed from the model.

- Counter-flows - Counter-flow reservations are identified by OASIS Automation based on the transaction's effect on flowgate flow and not included in the Automation results. Counter-flow reservations in offline studies are not modeled based on engineering judgment and experience.
- Partial Path transactions - A network analysis evaluation will be performed for all long-term firm transmission service requests based on specified source and sink. If service is accepted, but is a known partial path transaction (i.e., true source and sink is not specified) the transaction will not be included in the base model for evaluation of future requests.

5.3.2.2.2 FIRM NITS requests

Requests for NITS must be accompanied by a written Application including all of the information located *in Section 29.2 of the Tariff*. The Application must be submitted at or near the same time as the OASIS request is made. All requests for Designated Network Resources, whether associated with an initial request for NITS or a subsequent request for a new Designated Network Resource, must include in addition to the information required in the Transaction Specification Sheet of the Application for NITS, the information contained in the form, "MISO Request to Designate a Network Resource."

5.3.2.2.2.1 Review of Pre-existing Network Service or Equivalent

MISO will accept requests for initial NITS from Eligible Customers without a system capacity evaluation if the Network Customer provides adequate information for MISO to determine that the Network Load to be served and the resources designated to supply that Load have been planned for in the development of the Transmission System, and do not include new Load connection points or new resources that have not previously been associated with supply to the Eligible Customers Load responsibility. This will require the following to be demonstrated:

- Loads to be served are from existing connected Load points along with Load Forecast information for those existing Loads. Requests for NITS that include specification of newly connected Load points will require evaluation of transmission capacity.
- Resources designated in the Application that are not owned by the Eligible Customer must have existing transmission service arrangements in place (either as a designated resource in a network service arrangement, or PTP service from the resource to a portion or all of the Load responsibility). If no transmission service was previously required for supply from these designated resources, there must be an existing contract for supply from the resource.

- Resources designated in the Application that are owned by the Eligible Customer must have existing transmission service arrangements in place if the resource is outside of the Local Balancing Authority Area where any of the Load responsibility resides.

If all of the above is verified, Planning will sign the specification sheet, and indicate to the Tariff Administrator that the request for NITS should be accepted.

5.3.2.2.2.1 Procedure for Evaluating NITS or Service from New Designated Resource

If the conditions permitting acceptance of the request for NITS without a system capacity evaluation are not met, MISO planning staff will conduct a network analysis and SIS as necessary, using the same steps as in Sections II and III of this Procedure.

These studies shall be done in an analogous manner to the studies performed for an interconnecting generator that requests to be considered as a competing Network Resource for Load within the Local Balancing Authority Area. The Network Resources and Load responsibility of the Network Customer should all be modeled along with all other Loads and valid resources for the period under study. The Network Resources under evaluation should be modeled as delivering their output to the Load as indicated by the customer and approved by the Ad Hoc Group. Other Designated Network Resources for the Local Balancing Authority, or generators within the study region should be reduced proportional to capacity to balance the capacity of the new generator and maintain the net MISO Interchange. The network should then be tested to determine the ability of the aggregate Designated Network Resources for the Load responsibility to supply the Load under a variety of system conditions within reliability planning standards and criteria consistent with NERC, Regional Entities, and consistently applied Local Balancing Authority Area reliability criteria. These criteria may include among others, the outage of the most critical generator.

5.3.2.3 System Impact Study, Network Analysis Methodology

The ability of all MISO Network Resources (NRs) to be dispatched to their deliverable capacity to serve Network Load, needs to be respected while evaluating a new TSR; therefore, instead of a single, fixed base case dispatch, various generation dispatch scenarios are considered while evaluating the TSR, which adequately ensure that no NR is restricted due to granted transmission service. TSR evaluation is currently being performed using PSS®MUST software.

5.3.2.3.1 Contingencies to Evaluate

Single line outages of facilities 100 kV and above and pre-defined, multi-element contingencies in the study region would be included in the contingency file. Some areas will be monitored for single line outages of 69 kV and above. All such lists will be consistent with applicable NERC, regional and filed local planning standards and are provided to MISO by its Transmission Owner(s). The study participants, under the direction of MISO, should obtain the relevant lists for the current study, and determine any other conditions to be modeled.

5.3.2.3.2 Monitored Elements

Monitored element files include all facilities 100 kV and above in the study region. Some regions will be monitored for facilities 69 kV and above. In addition, a complete list of MISO and relevant non-MISO flowgates is also included in the monitored file.

5.3.2.3.3 Reliability Margins (TRM/CBM)

MISO will apply the Reliability Margins provided by Transmission Owner(s). Flowgates will be provided with CBM and TRM values to be applied to each flowgate. These values should be consistent with NERC and Regional standards applicable to these quantities. For Application of CBM and TRM in network analyses where ATC is evaluated on a regional basis, the following approach should be used. Transmission Reliability Margin (TRM) will be included as an adjustment to flowgate capability as provided by the Transmission Owner. This may be a MW reduction or a ratings percentage reduction. Capacity Benefit Margin (CBM) will be applied to all sink control areas based on the control area CBM methodology approved by the applicable NERC Regional Reliability Council (RRC). CBM preservation on intervening Local Balancing Authorities will be modeled by reducing the branch ratings on pre-defined flowgates by the designated CBM margin provided for that facility.

5.3.2.3.4 Transfer Simulation Participation Points

Transfers will generally be simulated with a Local Balancing Authority POR/POD transfer (i.e., proportionally increase generation in the source area and decrease generation in the sink area) unless a specific source/sink is known. In certain situations, the transfer may be modeled as generation to Load.

5.3.2.3.5 Pre-Transfer Case and Post-Transfer Case

The pre-transfer case is created by the MISO planning staff as outlined *in Section 5.3.2.2 of this BPM*. The post-transfer case is created by adding the capacity of the requested transmission service request to the pre-transfer case.

5.3.2.3.6 DC and AC Contingency Analysis

Based on the established source and sink subsystems, a DC contingency analysis is performed to obtain potential constraint pairs where each pair consists of 1 Monitored Element and 1 Contingency element. A generator sensitivity analysis is performed to obtain potential constraint pairs under the worst generation dispatch scenarios. Given the limitations involved in the DC analysis methodology, these results cannot be considered as final. However, they do provide a filtered list of potential constraints that needs to be studied further.

5.3.2.3.7 DC Analysis - Creating pseudo Flowgates using DC Analysis

The following steps take care of different dispatch pattern of NRs, i.e., all NRs have the right to use transmission service to serve Network Load up to their deliverable level. The transfer analysis is performed under a large number of reasonably worst-case generation dispatch scenarios. The point of creating all these pseudo Flowgates is to identify potential constraints under worst case conditions.

- The impact of each MISO NR unit, in the study region, on each filtered potential constraint is obtained by performing Monitored Sensitivity analysis. This impact is quantified as generator sensitivity factor (GSF, also referred to as ‘DF’).
- Based on the assumption of “80-20 rule”, the probability of all requested capacity being called on, is greater than or equal to twenty (20%) percent, i.e., at most fifteen (15) generators can be called on to their P_{max}. Therefore, up to fifteen (15) generators with GSFs greater than five (>5%) percent are dispatched to their P_{max} (maximum deliverable amount) sequentially starting from the highest GSF value. Doing so results in an increase in generation in the study region. Therefore, other generation in the study region should be decreased to keep the NSI of the study region the same.
- These pseudo Flowgates for each filtered potential constraint with its associated 80-20 worst dispatch pattern of NRs are created.

5.3.2.3.8 AC Analysis

Once the flowgate list is created by using the DC analysis under worst case scenarios, as described, the next step is to take these contingencies and then apply them to the study models, the near term and the out year cases.

- Perform AC contingency analysis on the pre-transfer case for near term and out year scenarios. Thermal overloads and voltage violations are saved.
- Perform AC contingency analysis on the post-transfer case for near term and out year scenarios. Thermal overloads and voltage violations are saved.

- The results obtained from the pre-transfer and post-transfer analysis are then compared to determine thermal and voltage constraints due to the study transfer by using the applicable reliability criteria. The cutoff for consideration as a thermal constraint is a five (5%) percent distribution factor of the study transfer on a facility overloaded beyond the applicable rating for system intact conditions, or a three (3%) percent distribution factor of the study transfer on a facility overloaded beyond the applicable rating for a contingency condition. The cutoff for consideration as a voltage constraint is a 0.01 per unit voltage change at a Bus beyond the applicable Bus voltage limits (applies to system intact and contingency conditions).

5.3.2.3.9 SIS Report

MISO shall prepare the SIS report within Tariff guidelines and provide the report to the customer within sixty (60) Days after receiving the SISA and the study deposit. *See the appendix B of this BPM*, for the SIS report format.

5.3.2.3.10 Ad Hoc Study Group Review and Draft Report

After assimilating all the results from the AC contingency analysis, MISO planning staff prepares a draft report and circulates it to the Ad Hoc Study Group. The goal of providing the report to the Ad Hoc Study Group is primarily to provide comments on the following items:

- Provide comments on the study models developed by the engineers for the near term and out year scenarios
- Provide comments on the overloaded transmission elements and provide mitigation which can include the following
  - Provide correct rating for the equipment
  - Identify existing transmission Operating Guides
  - Identify approved projects that mitigate the thermal constraint
  - Identify any existing Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) that are in place
- Provide comments on the validity of the constraints by looking at the contingencies or provide additional contingencies that should be run to meet their respective Planning principles and practices
- Provide preliminary cost estimates for fixing the overloads on transmission elements.

5.3.2.3.11 Evaluating Constraints and Accepting Transmission Service

After receiving feedback and comments from the Ad Hoc Study Group, the transmission planner will incorporate those comments into the report and post the final report on MISO's OASIS. The report will identify all the constraints that are impacted by the Transmission Service request under study and will provide pertinent information to the customer to ensure that the customer can make an informed decision. There are a few permutations and combinations that can occur and can have a different outcome depending on any of the following conditions.

- External Constraints Only: If the SIS identifies transmission constraints on non-MISO transmission system only, then MISO will assist the transmission customer in coordinating with the non-MISO Transmission Owner(s). The customer must submit the Specification Sheets within fifteen (15) Days after MISO requests the Specification Sheets on OASIS. MISO will provide the customer with all the associated conditions that must be outlined in the Specification Sheets for customer's review. By signing the Specification Sheets, the customer agrees to all the terms and conditions identified in the Specification Sheets. If the external constraint is identified as on the path constraint, then the constraint is ignored and it is not reported upon posting the final report on OASIS. A corresponding study will need to be completed by a non-MISO transmission provider to fulfill obligations for complete path reservation. However, all the procedures mentioned above will be followed if the identified constraint is off the path constraint.
- Internal Constraints Only: If the SIS identifies transmission constraints on MISO Transmission System only, then MISO will give the customer a few choices which are outlined as follows.
  - The SIS report will identify the minimum amount of transmission service that can be granted without any transmission upgrades. If the customer is willing to accept the partial service, then MISO will request the transmission customer to submit the Specification Sheets for the reduced amount. MISO will also check the AFC values for the next eighteen (18) Months to verify when the partial transmission service is available. If there are no negative AFC values for the next eighteen (18) Months then MISO will promptly accept and counteroffer the partial transmission service to start at the requested start time. If there is negative AFC before the start date of the TSR, within the next 18 Months, then MISO will defer the start date of the TSR until there are no negative AFC. Any counteroffers must have an identical value for the first twelve (12) consecutive Months, so if negative AFC is found for any of the first twelve (12) Months of the request the counteroffer will be zero (0) for the first twelve (12) Months. The customer can submit Monthly firm transmission service requests for those Months in the twelve (12) Month period that have positive AFC. If the requested transmission service is NITS, then MISO will also request the transmission customer to submit an eDNR on MISO OASIS within fifteen (15) Days along with the Specification Sheets.

- The SIS report identifies the upgrades in order to accommodate the full request. Upon posting the final report the customer will be issued a Facility Study agreement and also a request to submit Specification Sheets to accept partial offer as per the SIS report. See the Facility Study section for further details.

- Internal and External Constraints: If the SIS report includes constraints on both MISO system and non-MISO transmission system then MISO will take the same steps as identified and explained in Sections 1 and 2.
- No Constraints: If there are "NO" constraints identified on the Transmission System then the transmission service planning engineers will look at the AFC results and take action accordingly. If there are no AFC and NNL violations within eighteen (18) Months of the queued date of the requested TSR, then MISO planning staff will request the customer to submit Specification Sheets within fifteen (15) days. If it is NITS, then the customer will also be required to submit an eDNR on MISO OASIS along with the Specification Sheets. After the MISO planning staff receives the Specification Sheets and the eDNR information, the MISO planning staff will request the Tariff Administrator to accept the transmission service on OASIS.

A facility will be considered constrained if it becomes overloaded when modeling the transaction or aggravates an existing overload. The constraint must be impacted by the transaction by a five (5%) percent distribution factor with system intact, or three (3%) percent under contingent conditions. Regardless of the distribution factor, any impacts under 1MW will be ignored.

Table 5.3.2.3.10-1: SIS Impact Results Matrix

Near Term Results	Out Year Results	Status
Clean	Clean	Accepted
Clean	Constraints	Accepted with no rollover rights or Facility Study is offered
Constraints	Clean	MISO planning staff determine what upgrade resolved problem in the near term scenario, then accepts conditional on that upgrade. An option would be provided if the customer can accept the service in the out year time frame without any upgrades.
Constraints	Constraints	MISO planning staff engages Ad Hoc Study Group to resolve constraints

5.4 Facility Study Process

5.4.1 Study Coordination Contacts (Ad Hoc Study Group)

When MISO determines that a Facility Study is needed, it will notify potentially affected Transmission Owner(s) of the need for study. These Transmission Owner(s) should indicate if they believe the proposed request could impact their systems, and if they desire to be part of the Ad Hoc Study Group, as provided *in Section 5.5.1 of this BPM*, to evaluate the request.

5.4.2 Tender of Facility Study Agreement

In accordance with the Tariff, MISO will tender a Facility Study agreement to the customer within thirty (30) Days of completion of the SIS. If the Facility Study agreement is not executed within fifteen (15) Days the Application will be terminated and MISO planning staff will notify the Tariff Administrator to refuse the request. The Facility Study agreement will include an estimate of the actual cost to perform the study. This cost estimate will include the cost of work by MISO planning staff and any other participants, including consultants, involved in the coordinated study. The Facility Study agreement will also include a good faith estimate of the time to complete the study. The time to complete the study will depend on the number of studies ahead in the queue, and whether certain studies can be done in parallel with each other. The Tariff requires facilities studies be completed within one-hundred twenty (120) Days of receiving the executed study agreement and deposit.

The study deposit for a Facility Study is $100,000 which is refundable if there are any unused remaining balances after the Facility Study is complete. If the customer requests to stop all Facility Study work because it wishes to withdraw the TSR, then MISO will stop all work and refund the remaining balance.

There are instances when the cost of the actual study is expected to exceed the initial study deposit. In those situations, MISO will request the customer to deposit additional funds to ensure that the Facility Study continues per schedule. If the customer fails to make any additional deposit, MISO will stop all work until the additional deposit is received.

5.4.3 Performing the Facility Study

MISO planning staff will form an Ad Hoc Study Group as provided *in Section 5.5.1 of this BPM*. MISO then prepares the study cost estimate, project timeline, and study agreement.

- MISO Planning contacts the impacted area (i.e., Local Balancing Authority where the constraint is located) and, if required, a third-party contractor to determine Ad Hoc Study Group membership and cost estimates

- MISO Planning will initiate and coordinate the Ad Hoc Study Group Facility Study process.

The Facility Study report will determine a good faith estimate of the following:

- The cost of direct assignment facilities to be charged to the transmission customer
- The transmission customer's appropriate share of the cost of any required network upgrades
- The time required to complete such construction and initiate the requested service.

After the Facility Study report is complete, it is reviewed by MISO planning staff before it is transmitted to the customer. At this juncture, the transmission customer has the following options.

- It can either opt for a reduced amount of available transmission service, as identified in the SIS report.
- Proceed with a facility construction agreement and agree to fund and build the transmission upgrades for the full requested amount which caused the Facility Study to be performed.
- Withdraw the TSR

5.4.3.1 Specification Sheets

Prior to MISO moving the request to an *Accepted* status, an executed *specification sheet* must be received from the customer. The *specification sheet* gives the details of the service, including the specific source, sink, term of the transaction, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have fifteen (15) Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.4.4 Facilities Construction Agreement

When the results of the Facilities Study indicate the need for the Transmission Customer to finance the construction of Network Upgrades, those requirements will be memorialized in a 3-party Facilities Construction Agreement which must be filed at FERC either executed or unexecuted prior to commencement of the transmission service. This agreement will delineate the roles and responsibilities of each party to the agreement.

5.5 Miscellaneous

5.5.1 Ad Hoc Study Group

Under the direction of MISO, the Ad Hoc Study Group will participate in the analysis and reporting of the available transmission capacity to accommodate the transmission service request. The Ad Hoc Study Group will perform, as necessary and in accordance with the provisions of the Tariff, System Impact and Facilities Studies. MISO will form and direct the activities of the Ad Hoc Study Group. It is anticipated that the study group formed to evaluate a transmission service request will be made up of representatives from the source and sink Local Balancing Authorities as well as interested intervening Local Balancing Authorities. It is anticipated that MISO will perform preliminary distribution factor calculations or other analysis to determine the extent of interactions with intervening systems. The Ad Hoc Study Group may also include third party contractors to assist in performing the analyses.

The possible participants in System Impact and subsequent Facilities Studies will include:

- Transmission Customer
- MISO planning staff
- Transmission Owner(s) of facilities potentially impacted by the request
- Adjacent transmission providers/RTO(s)
- Regional or subregional study groups in place in the areas potentially impacted by the request

The role of MISO planning staff will generally be to:

- Establish study time line – Tariff defined
- Prepare the study agreements
- Provide the system models to be used in studies
- Provide the study guidelines by which studies should be performed
- Determine whether an impact study is needed to resolve constraints to accepting service
- Ensure the accuracy of studies, either by MISO planning staff, or on behalf of MISO by contractors or members of the Ad Hoc Study Group
- Coordinate the formation and activities of the Ad Hoc Study Group
- Review any studies performed on behalf of MISO for accuracy and for compliance with the Tariff and applicable standards and procedures
- Provide study results and reports to customer
- Handle billing and payment of study costs

The role of other participants in the studies will generally be to:

- Indicate desire to participate in the Ad Hoc Study Group
- Provide information to MISO to assist in preparing study agreements
- Assist in updating any models used for studies
- Perform studies, or aspects of studies, as requested by, and on behalf of, MISO according to study guidelines of MISO, and applicable standards
- Provide review and comments to MISO of study results with regard to their systems
- Provide study results and reports to MISO
- Respond to MISO questions and assist MISO in responding to customer questions concerning study results

Note: If transmission service is being requested across the border between PJM and MISO, the procedures under “Joint and Common Market,” as provided at the following web-link, will be invoked: MISO PJM JOA

If MISO finishes its SIS or the Facility Study before the customer has received the results for the other leg of the transmission service, then MISO will wait to request the transmission service specification sheets until the customer has results from both transmission providers (PJM and MISO). Once the results from PJM’s planning department are available, MISO will request the customer to submit the Specification Sheets within fifteen (15) Calendar Days after initiating the request. Customer’s failure to submit the Specification Sheets within fifteen (15) Calendar Days will result in the refusal of the TSR on MISO’s OASIS.

5.5.2 Reserved

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5.5.3 Group TSR Studies

If multiple customers request TSRs on a common path due to economic or other engineering reasons, MISO shall study all those TSRs in one single group and shall call it a single group study. The cost to perform the System Impact Study and Facility Study shall be prorated based on the individual size of each TSR in the group. The appropriate percentages to calculate the prorate costs to perform the studies shall be shared amongst all the transmission customers at the commencement of the study. The percentage costs for any common upgrades will also be calculated based on the prorate share of the size of the TSR. Any other transmission upgrades costs that are unique to each TSR in the group will be direct assigned to that TSR’s customer.

5.5.4 Specification Sheets

Prior to MISO moving the request to an *Accepted* status, an executed Specification Sheet must be received from the customer. The Specification Sheet gives the details of the service, including the specific source, sink, term, amount, and lists any prerequisite conditions that must be met prior to commencement of service, such as Network Upgrades. Once the customer is notified via OASIS, they will have fifteen (15) Calendar Days to provide those forms or the service will be deemed withdrawn and the request will be refused.

5.5.5 Provisional Generator Interconnection Agreements

Point-to-Point transmission service is available for units with provisional interconnection agreements. Network Integrated Transmission Service is not available to units with provisional interconnection agreements.

5.6 Coordination of TSR studies between MHEB, MPC and MISO

This procedure will govern the TSR study coordination for the Long-Term Firm Transmission Service Requests on MHEB, MPC and MISO transmission systems where one of the three parties may be an Affected System TSP for the TSR. The entire coordination procedure is documented in Appendix O of this BPM.

5.7 Appropriate Links

OASIS Transmission Studies page. Contains links to the following pages and reports:

- System Impact Studies page which contains links to reports.
- Facility Studies page which contains links to the reports.
  - FERC metrics report links: FERC_Order_890_Performance_Metrics
  - AFC procedure links: ATC_Information
  - MISO Network and Point to Point Specification Sheets: Spec. Sheets
  - Tariff and Rate Schedules: Long-term Transmission Service Request
  - Transmission Services webpage: Long-term Transmission Service Request

6 Non-Cyclical Planning Studies

6.1 Review of Market Participant Funded Projects

Process for evaluation of Market Participant funded projects (MPFP) is described in this section. Pursuant *to Section III.A.2 of Attachment FF of the Tariff*, Market Participant funded projects are defined as network upgrades fully funded by one or more market participants but owned and operated by incumbent Transmission Owner(s). This process applies to those network upgrades that are neither currently included in the MISO Transmission Expansion Plan (MTEP) Appendix A nor targeted for approval within the current planning cycle.

- These Market Participant funded projects are not "Merchant Upgrades" which are constructed, owned and operated by Market Participants or Merchant Transmission Owner(s).
- Pursuant to Order 1000, since these network upgrades are not approved as part of a regional planning process for purposes of cost allocation but by nature are directly assigned to the Market Participant, such upgrades are not eligible for elimination of Right of First Refusal (ROFR).

6.1.1 Process Steps

- **Step 1**: all such network upgrades shall be required to be submitted using the MPFP proposal form, which needs to be sent to MISO via electronic mail at the address indicated on the form, by Market Participants by September 15th for inclusion in the MTEP to be approved in December of the following year. Each project will receive a time-stamp date of receipt. Exceptions to the submittal deadline shall be:
  - Allowed where network upgrades are less than $1 million and deemed to not have material impact on the network transmission system by MISO and applicable Transmission Owner(s).
  - Projects that have been proposed as economic projects and have been evaluated in the MCPS process and all appropriate studies have been completed by the 3rd SPM but did not meet MISO's criteria and were, therefore, not selected as Market Efficiency Projects.
- **Step 2**: these projects will follow the same process as TO submitted projects in the MTEP planning cycle.
- **Step 3**: to the extent, prior to commencement of studies, that a proposed network upgrade by the Market Participant is deemed either infeasible or inconsistent with Transmission Owner facility standards, the applicable Transmission Owner(s) shall propose alternative transmission upgrades for market participant funding. These transmission upgrades may be upgrades to the existing system or new facilities.
- **Step 4**: Market Participant and applicable Transmission Owner(s) shall enter into a System Facilities Study Agreement by the first annual regularly scheduled Subregional Planning Meeting (SPM), which is typically held in December. Agreements shall be consistent with Attachment D-2 where all planning, engineering and other study costs associated with the MP request shall be borne by the Market Participant.

- **Step 5**: MISO will present proposed MPFP along with all other proposed MTEP projects at the first annual regularly scheduled SPM.
- **Step 6**: MISO in collaboration with applicable Transmission Owner(s) shall conduct an engineering analysis which would include:
  - Detailed engineering study of appropriate network upgrade needed to mitigate applicable constraint/s and associated estimate costs.
  - A reliability "No-Harm" study to identify detrimental impact to reliability of the existing system if any. Reliability no harm study shall be conducted consistent with NERC Planning Standards, Regional Entity standards, Transmission Owner's Planning Criteria and Tariff and BPM requirements. To the extent, the proposed network upgrades "harm" the reliability of the existing system, additional network upgrades including associated costs shall be developed.
- **Step 7**: Market Participants shall execute Facility Construction Agreement (FCA) with applicable Transmission Owner(s) by the 3rd annual SPM.
  - MISO will notify Market Participant of the final project selection and estimated cost.
- **Step 8**: MISO will communicate the final project selection and estimated cost of the MPFP including any additional necessary upgrades and associated cost at the 3rd SPM including the MPFP in the ongoing MTEP analysis at that time.
- **Step 9**: MISO will evaluate eligible financial rights associated with the final network upgrades in accordance with the Tariff.
- **Step 10**: MISO will include the network upgrades in its current MTEP once the FCAs are in place.

The above outlined process does not in any way preclude individual Market Participants and Transmission Owner(s) mutually agreeing to complete their respective milestones on an accelerated schedule.

6.1.2 Priority of Competing Project Proposals

In the event that multiple Market Participants submit project proposals that are electrically similar, MISO will make a determination in collaboration with the affected Transmission Owner as to whether the projects are effectively the same project[28]. If the projects are determined to be effectively the same project, the priority for the project shall be determined by the time-stamp date of receipt of the MPFP Proposal Form, unless otherwise agreed to by the impacted Market Participants.

[28] Consideration is given to feasibility and compatibility of the multiple proposals and congestion issues addressed by the proposals.

6.2 Generator Retirement and Suspension Studies and System Support Resources (SSR)

6.2.1 Introduction

The Attachment Y program defined *in Section 38.2.7 of the Tariff* provides a mechanism to maintain Transmission System reliability by retaining a Generation Resource as a System Support Resource when the change in status of the generator would result in reliability issues that can only be mitigated with the continued operation of the generator. System Support Resources (SSR) are Generation Resources or Synchronous Condenser Units (SCUs) which are required by MISO to maintain system reliability, if such Generation Resources or SCUs are uneconomic to remain in service and otherwise would be retired or placed into suspension.

MISO in collaboration with the ~~affected Transmission Owners~~ Ad Hoc study group, *as defined in Section 5.5.1 above*, performs an Attachment Y reliability study to assess the impacts of potential generator retirements and suspensions on system performance to determine if violations of NERC or local TO planning criteria occur as a result of the change in status. If reliability issues cannot be resolved with available alternative mitigation plans, the generator is retained and compensated by MISO through an SSR Agreement and costs are paid by the Loads that benefit from the SSR. While the Attachment Y analysis seeks to identify system reinforcements needed to accommodate the retirement/suspension of the generator, SSRs are a last resort measure used as interim mitigation until other transmission upgrades or alternative solutions are available and therefore are not considered to be planning solutions.

6.2.2 Applicability and Notification Requirements

Attachment Y Tariff Notification provisions apply to all Generation Resources as well as units that are interconnected to MISO transmission facilities but pseudo-tied out of MISO market. SSR eligibility will apply to market Generation Resources if the generator has been determined to be required to address reliability issues. Generation Resource Owners are required to submit planned retirements and suspensions to MISO at least ~~twenty-six (26) weeks~~ four full Quarterly Study Periods in advance of the intended change of status for the full capacity or a reduction in capacity of the generator. The Attachment Y Notice must be executed by an officer of the company authorized to make a binding decision and must contain complete information including the change of status dates. Attachment Y Notices are considered definitive decisions and subject to limited rescission rights as provided in the Tariff.

Attachment Y Notices are treated as confidential information and remain confidential until the date of retirement unless the owner publicly releases the information. If reliability issues are identified that cannot be resolved with available mitigation the Attachment Y will no longer be considered confidential and alternatives will be sought in an open stakeholder process.

6.2.3 Study Scope Development

As required by the Tariff, MISO works with ~~affected TOs~~ the Ad Hoc group to define the study parameters for evaluating the impact of the generator change of status and may consider other available studies. The Attachment Y reliability study will include at a minimum thermal and voltage analysis to evaluate steady state system performance. Additional analysis may be included to evaluate system stability and/or import limitations under the expected system conditions. MISO SSR Planning staff consults with MISO Operations staff to consider any additional operational requirements associated with the Attachment Y generator.

Analysis will reflect the conditions expected for the period of the change in status including any relevant topology changes and forecasted Load levels. Generation dispatch will consider any expected changes in generator availability and will be based on security constrained economic commitment and dispatch. Analysis will identify any issues that require mitigation to meet NERC and local planning criteria and include the determination of impact of the Attachment Y unit under study on those issues. SSR need is determined by the presence of unresolved reliability criteria violations where the unit under study meets SSR impact criteria as discussed *in Section 6.2.5 below*.

6.2.4 Power Flow Model Preparation

The Attachment Y reliability study cases are derived from MTEP study models to produce a near-term model which represents the initial year of the retirement/suspension of the generation resource or SCU and a mid-term model which represents the longer-term outlook as appropriate. The models contain firm transactions appropriate for reliability analysis and are updated to reflect the topology changes associated with MTEP Appendix A and Target Appendix A projects planned to be completed for the study period. The forecasted Load conditions used in the Attachment Y reliability study reflect seasonal conditions such as peak and shoulder Load levels where appropriate. Generation commitment and dispatch is based on Security Constrained Economic Dispatch (SCED) of available Generation Resources. Generation dispatch also considers the operational limitations related to Qualified Facilities (QF) and unit commitment requirements defined in available Operating Guides.

For each study period, two model scenarios are created which represent the "before" and "after" states of the generator/SCU retirement or suspension. The models which represent these two (2) scenarios are created in the following steps:

- **Step 1**: The "after" retirement/suspension model is created first as follows:
  - An approved MTEP series model is selected based on the appropriate seasonal conditions.
  - MTEP Appendix A and Target Appendix A transmission projects are applied/removed to create model topology consistent with the study period.
  - Previously retired and unavailable generators are removed from service and capacity replaced from other available MISO Generation Resources.
  - Generation dispatch prescribed by QF and Operating Guide requirements is manually set.
  - SCED bid input files are updated to excluded the non-dispatchable resources.
  - SCED is applied to the model to dispatch MISO generators.
- **Step 2**: The "before" retirement/suspension model is created from the "after" retirement/suspension model as follows:
  - The study generator(s) is placed in-service and generator output (P_{gen}) is set to the appropriate Generator Verification Test Capacity (GVTC) value submitted by the resource owner to MISO *as per BPM-011 - Resource Adequacy*.
  - All other generation is scaled down in the MISO market areas, excluding the local area(s) where the study generator is located, by the total amount of the generation under study.

6.2.5 Reliability Evaluation

The Attachment Y reliability study applies NERC and local planning criteria in evaluating the impact of the retirement/suspension on transmission system performance for NERC category P0 conditions and under simulation of NERC category P1-P2 contingent events, selected NERC category P3-P7 events, and planned maintenance plus forced outage events that are included in local planning criteria. The need for the SSR is determined by Transmission System reliability issues where thermal or voltage violations are caused by the removal or reduction of the study generator and cannot be resolved without the use of the SSR Unit. Allowed mitigation measures proposed to address the violations of planning criteria are investigated for effectiveness, and unresolved issues are then documented in justifying the need for the SSR Unit.

The evaluation criteria for the Attachment Y reliability study is further described below:

- The monitored areas include the Transmission Owner area where the Attachment Y generator(s) is located and nearby affected TO areas. Monitored Transmission System facilities include 100 kV and above facilities in the affected areas and 69 kV and above facilities that are under MISO functional control. These monitored facilities also include tie lies to neighboring areas.
- Branch Loading is compared against the normal thermal rating for NERC category P0 conditions (system intact), and against the emergency thermal rating for category P1-P7 contingencies.
- Transmission Bus voltages are evaluated with respect to steady state Bus voltage criteria specified by the Transmission Owner local planning criteria. Generally, pre-contingency voltage limitation is between 1.0 and 1.07 p.u. for 500 kV and above Buses, and between 0.95 and 1.05 p.u. for Buses below 500 kV. Post-contingency voltage limitation is normally between 0.9 and 1.1 p.u., if it is not specified. All 100 kV and above post contingent voltages are assessed after automatic transformer tap change and shunt switching have been performed.
- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the “after” scenario is equal to or greater than:
  - Five (5%) percent of the “to-be-retired” unit(s) MW amount (i.e., 5% PTDF) for a “base” violation compared with the “before” scenario; or
  - Three (3%) percent of the “to-be-retired” unit(s) MW amount (i.e., 3% OTDF) for a “contingency” violation compared with the “before” scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than one (1%) percent as compared to the “before” scenario.
- Available mitigation may be applied for the valid NERC category P1-P7 thermal and voltage violations described above as allowed by NERC standards.
- Where Transmission Owner planning criteria prescribe requirements for planned outages, analysis of NERC category P3 and P6 events in shoulder conditions will be used to identify reliability issues and assess the need for mitigation.
- Angle/voltage stability studies and import capability will be performed as needed.

- The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available. Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.
- The use of planned redispatch or load shedding as a planned solution to unresolved violations shall be summarized with the Ad Hoc study group. Specific reliability issues addressed by generation redispatch or load shedding will be reported to the study group if they exceed any of the following values:
  - Generation Redispatch > 600 MW increment/decrement
  - Load shed > 100 MW
  - Equipment Reconfiguration > 1
- When mitigation value(s) surpass the expressed threshold(s) above, MISO will inform the Ad Hoc study group of the violation. While surpassing the threshold(s) does not immediately designate the need for SSR, MISO will consider Ad Hoc study group feedback when deciding whether the Generating Resource should enter SSR negotiations.

Analysis results are reviewed with the ~~Transmission Owner~~ Ad Hoc group to validate the findings and identify any immediately available remediation. New or previously planned transmission upgrades needed to address the violations in the near term should be submitted as a MTEP Target Appendix A project for approval in the applicable MTEP planning cycle.

Upon completion of the reliability analysis MISO prepares an initial report containing the detailed study results and conclusion of the analysis which is reviewed and confirmed with the ~~affected Transmission Owner study~~ Ad Hoc group study participants. MISO sends a notification letter to the asset owner to provide an opportunity to withdraw the Attachment Y Notice without further consideration. If the notice is not rescinded within fifteen (15) Business Days, MISO sends a letter with the final Attachment Y study decision. MISO shall use reasonable efforts to provide this decision to the owner within 150 calendar days after the start of the individual Attachment Y Reliability Study.

If no reliability issues are found or if transmission upgrades are planned to be implemented before the retirement or the date of need, or other mitigation options exist, the Attachment Y generator is approved to Retire or Suspend. For any unresolved violations of planning criteria MISO informs the asset owner of the need to pursue a SSR Agreement and posts a public notice of the reliability need for the Attachment Y generator and a public version of the initial report on the MISO OASIS. Additional analysis is performed to identify the Loads subject to SSR cost responsibility.

6.2.6 Alternatives Evaluation

After notifying the asset owner of the SSR need, MISO convenes a public Technical Studies Task Force meeting to review the Attachment Y reliability issues and to seek feasible alternatives to avoid the need for the SSR Agreement in a stakeholder-inclusive process *in accordance with Section D.1.b of Attachment FF - Transmission Expansion Planning Protocol*. MISO works with stakeholders to explore other potential alternatives including generation redispatch, system reconfiguration, new or expedited transmission upgrade projects, new generation resource or SCU installation, remedial action plans, or demand response solutions that are comparable to the SSR Unit.

6.2.7 System Support Resource Agreement

If no feasible alternative is identified, MISO and the Market Participant negotiate and execute an SSR Agreement (Attachment Y-1) to maintain availability of the generator for reliability needs. The SSR Agreement defines the terms of service to permit MISO to dispatch the generator in exchange for compensation for the total cost of service for the generator. The total compensation includes a component of costs filed directly with FERC by the Market Participant and variable compensation component based on the market revenues and charges determined in the market settlements process. MISO files the SSR Agreement along with the associated schedule containing allocation of costs for the SSR Unit for approval by FERC. MISO will conduct a periodic review, at least annually, of the continued need for the SSR. The review will include a reliability analysis of the expected system conditions for the next term of the SSR Agreement and evaluation of any alternatives that can be implemented before the renewal of the agreement.

6.2.8 System Support Resource Agreement Cost Allocation Methodology

6.2.8.1 Overview

MISO SSR Cost Allocation Methodology describes the approach for assigning costs associated with retaining a Generation Resource as an SSR Unit to maintain reliability of the Transmission System. Costs for maintaining the SSR generation are allocated to LSE's that benefit from the operation of the SSR Unit. Analysis is performed to identify the Loads that contribute to constraints identified in the Attachment Y reliability study, and the associated LSE's are assigned a share of the cost responsibility based on their Monthly peak energy withdrawals. The method for cost allocation is filed with the associated SSR Agreement for approval by FERC.

The methodology addresses both thermal and voltage related reliability issues that can be caused by the retirement/suspension of a generation resource. The process for determining the Load impacts requires the calculation of Load distribution factors (DF) and utilizes readily available powerflow analytical tools. The distribution factor is determined for each Load Bus in the MISO system relative to the MISO generation reference which reflects the replacement power for the SSR Unit under study. That is if the SSR Unit were not available the power would be provided by the MISO market generation to serve the system Loads. The SSR Unit avoids the constraints, and thus provides benefit to the Loads contributing to the constraint.

The determination of cost responsibility and allocation of the costs to the Loads requires the analysis of each constraint identified in the Attachment Y reliability study to calculate the distribution factors of MISO Load Buses. The distribution factors are calculated with respect to a MISO-wide generation reference with generator participation based on modeled unit capacity (P_{max}). This represents the dispatch of MISO market generation to replace the power otherwise provided by the SSR Unit. Load distribution factors for thermal constraints can be calculated by standard linear power flow techniques. Voltage issues require the establishment of proxy interface that represents a constraint for the import of replacement power to the area of voltage decline and requires additional steps to define the interface.

6.2.8.2 Identification of Impacted Load Buses and Associated Elemental Pricing Nodes

6.2.8.2.1 Thermal Constraints

In the case of thermal violations the Load distribution factors are calculated directly by linear power flow analysis to obtain the distribution factor (DF) or shift factor of the constraint flow to the power injection at the Load Bus. This constraint is modeled as an OTDF constraint that includes the impact of the contingent event that was identified to cause the thermal violation. For each constraint identified in the Attachment Y study, distribution factors are calculated using the MISO market Network Model that is the most recent final model available at the time the analysis is performed for the new SSR Agreement or renewal of the contract. A minimum distribution factor cutoff of one (1%) percent is used as a reasonability threshold to eliminate the Buses that have minimal impact. Use of the Network Model allows direct mapping of the Network Model Load Buses to the Elemental Pricing Nodes (EP Nodes) used in settlements.

6.2.8.2.2 Calculation of Load Distribution Factors for Thermal Constraint

For each unresolved thermal constraint identified in the Attachment Y study, linear power flow analysis is performed to determine how much impact Load Buses in the MISO system have on the constraints that are caused or made worse by the SSR Unit.

- **Step 1:** Using the quarterly MISO market Network Model, the Load distribution factors are calculated with respect to the MISO aggregate market generation reference using DC powerflow analysis to determine the change in flow of the monitored thermal constraint due to the MW Load at each Bus.
  - Define subsystem for distribution factor reference (include MISO generation Buses)
  - Define subsystems for individual Load Buses in MISO footprint
  - Create monitor list of constraints using thermal monitored facilities and contingent elements
  - Using Network Model base case, run DC powerflow analysis to calculate distribution factors of Load Buses in MISO footprint for each constraint identified
- **Step 2:** Load Buses with distribution factors that exceed one (1%) percent minimum threshold are selected and mapped to the corresponding Elemental Pricing Nodes using the MISO Commercial Model
  - Analysis results are filtered to retain all Load Buses with distribution factors above one (1%) percent
  - Using the MISO Commercial Model data, Elemental Pricing Node names are mapped to the associated Load Buses
- **Step 3:** Elemental Pricing Nodes are ranked in descending order according to their Load distribution factors
- **Step 4:** Load distribution factors are summed to obtain a total
- **Step 5:** Eighty percent of the total of the distribution factors is calculated as the cutoff threshold above which Loads are selected for cost allocation
- **Step 6:** Elemental Pricing Nodes with the same Load distribution factors at the eighty percent cutoff threshold are included for cost allocation

6.2.8.2.3 Voltage Constraints

For voltage violations and voltage stability issues, the Loads in voltage constrained area contribute to the voltage decline or voltage collapse condition. Load Buses that contributed to the voltage issues are first identified by steady state or voltage stability studies and further evaluated using modal analysis traditionally used to identify participating Buses at the point of instability. More detailed examination of the transmission network is necessary to identify the weak interfaces where the system would separate to avoid further propagation of a voltage collapse event. The boundary of the area susceptible to the voltage violations or potential voltage collapse is defined as a proxy interface of transmission facilities that completely encloses the voltage constrained area and thus all Loads within the area are considered equal contributors the voltage issues (distribution factor is ~1.0).

Once the proxy interface has been defined, the MISO market Network Model that is the most recent final quarterly model available at the time of the analysis for the new or renewed SSR Agreement is used to allow mapping of the Load Buses to the corresponding EP Nodes. Since all Load Buses that are within the bounded area have the same distribution factor, all Loads will be allocated a portion of the SSR costs. Use of the Network Model allows direct mapping of the Network Model Load Buses to the Elemental Pricing Nodes (EP Nodes) used in settlements.

6.2.8.2.4 Determination of Voltage Constraint Proxy

For each voltage violation constraint or voltage stability constraint identified in the Attachment Y study, the boundary of the voltage constrained are is determined by the location of the Buses with voltage violations or Buses participating in voltage collapse. Examination of the transmission network topology is used to determine the appropriate interface to establish a boundary around the affected voltage constrained area.

- **Step 1:** Using the Attachment Y study model, Buses with voltage violations are identified
- **Step 2:** Using the Attachment Y study model, voltage stability assessment (P-V analysis) scenario is defined to simulate transfers to replace Attachment Y generation with other MISO market generation.
  - Create sink subsystem for the generator under study (include SSR Units)
  - Define all areas specified in the Attachment Y study as monitored areas
  - Enable modal analysis and include Attachment Y study areas for monitoring
- **Step 3:** Voltage stability analysis is performed to determine the point of instability for each contingency
- **Step 4:** At the stability limit, modal analysis is performed to indicate the Buses participating in the voltage collapse for the mode with the lowest eigenvalue (near zero).
- **Step 5:** Using the set of Buses with voltage violations or participating in voltage collapse, the boundary of the voltage constrained area is determined and a corresponding interface is defined by transmission elements that fully enclose the area

- The interface is determined by weak transmission system and lower kV lines that are likely to separate the voltage constrained area from the rest of the interconnection following a disturbance
- The voltage constrained area is the minimum area enclosed by the interface that includes the identified Buses and the SSR generator

- **Step 6:** The voltage proxy constraint is defined by the interface of the voltage constrained area

6.2.8.2.5 Calculation of Load Distribution Factors for Proxy Voltage Constraint

- **Step 1:** Using the quarterly MISO market Network Model, the Load distribution factors are calculated with respect to the MISO aggregate market generation reference using DC powerflow analysis to determine the change in flow of the monitored voltage proxy constraint due to the MW Load at each Bus
  - Define subsystem for distribution factor reference (include MISO generation Buses)
  - Define subsystems for individual Load Buses in MISO footprint
  - Using Network Model base case, run DC powerflow analysis to calculate distribution factors of Load Buses in MISO footprint for each proxy constraint identified
- **Step 2:** Load Buses with distribution factors that exceed one (1%) percent minimum threshold are selected and mapped to the corresponding Elemental Pricing Nodes using the MISO Commercial Model
  - Analysis results are filtered to retain all Load Buses with distribution factors above one (1%) percent
  - Using the MISO Commercial Model data, map the Elemental Pricing Node names to the associated Load Buses

6.2.8.3 Calculation of Cost Allocation Shares

6.2.8.3.1 Determination of the Impacted Load Zone Commercial Pricing Nodes

Using the quarterly MISO Commercial Model, the Elemental Pricing Nodes that are associated with the impacted Load Buses are used to identify the Load Zone Commercial Pricing Nodes for the current billing Month.

6.2.8.3.2 Identification of the coincident peak Actual Energy Withdrawal for Billing Month for Impacted Load Zone Commercial Pricing Nodes

For each Load Zone Commercial Pricing Node identified in the previous step, MISO determines the Monthly_PEAK $_{\text{CP NODE}}$, which is the hourly Actual Energy Withdrawal volume during the billing Month based on the coincident peak hour across all Impacted Load Zone Commercial Pricing Nodes.

6.2.8.3.3 Determination of the portion of the Load Zone Commercial Pricing Node benefiting from the SSR for the billing Month

To determine the Elemental Pricing Node Volume (EPN _MW), using the Peak Hour in the billing Month for a Load Zone Commercial Pricing Node, the Daily Load Weighting Factor (DLWF)[29] for each Elemental Pricing Node associated with the Load Zone Commercial Pricing Node is multiplied by the Monthly_PEAK.

Equation 6.2.8.3.3-1: Elemental Pricing Node Volume

$$\boxed{EPN\_MW = Monthly\_PEAK_{\ CP\ NODE} \times DLWF_{EP\ NODE}}$$

For each impacted Load EPNode, the distribution factors are summed for all constraints identified by the Transmission Provider to determine the aggregate Load distribution factor (EPN_LDF).

Equation 6.2.8.3.3-2: Aggregate Load Distribution Factor

$$\boxed{EPN\_LDF = \Sigma\, DF_{CONSTRAINT}}$$

The Elemental Pricing Node Volume is multiplied by the aggregate Load distribution factor (EPN_LDF) for each Elemental Pricing Node, to determine the Elemental Node Impact Volume (EPN_IMP_MW).

Equation 6.2.8.3.3-3: Elemental Node Impact Volume

$$\boxed{EPN\_IMP\_MW = EPN\_MW \times EPN\_LDF}$$

The EPN_IMP_MW is summed for all Elemental Pricing Nodes for the Load Zone Commercial Pricing Node for a total Load Zone Commercial Pricing Node Impact Volume (IMP_MW).

Equation 6.2.8.3.3-4: Commercial Pricing Node Impact Volume

$$\boxed{IMP\_MW_{CP\ NODE} = \Sigma\, EPN\_IMP\_MW}$$

29 The Daily Load Weighting Factor is a daily calculation of the ratio of the EPNode Load to the total Load for the parent CPNode Load as determined by real time data, and is used to estimate the EPNode fraction for the purpose of settling the prices in the market settlements process. This calculation is performed seven (7) Days prior to the market day from data supplied by the State Estimator, which is "[a] software program used by the Transmission Provider to create a real time assessment of the condition of the Transmission Provider Region." Tariff Section 1.S.

6.2.8.3.4 Determination of the Cost Share for the Load Zone Commercial Pricing Node

A Commercial Pricing Node's percentage Share (CPN_SHARE) for a SSR Agreement is equal to the IMP_MW for that Load Zone Commercial Pricing Node divided by the total IMP_MW for all Load Zone Commercial Pricing Nodes that benefit from the SSR Unit(s).

Equation 6.2.8.3.4-1: Commercial Pricing Nodes Percentage Share

$$\boxed{CPN\_SHARE_{SSR} = IMP\_MW_{CP\ NODE} / \Sigma\ IMP\_MW_{CP\ NODE}}$$

6.2.8.3.5 Determination of the Sum of the Load Zone Commercial Pricing Node shares by LSE

Sum the CPN_SHARE by Asset Owner, which represents the LSE, to determine the total LSE percentage Share (LSE_SHARE) for the SSR Agreement.

Equation 6.2.8.3.5-1: Commercial Pricing Nodes Percentage Sum

$$\boxed{LSE\_SHARE_{SSR} = \Sigma\ CPN\_SHARE_{SSR}}$$

6.2.8.3.6 Determine the Net Charge or Credit Assigned to Each LSE

The net charge or credit for each LSE (SSR_AMT_{LSE}) is obtained by multiplying the LSE_SHARE_{SSR} by the net charge or credit calculated for the SSR Agreement ($TOTAL\_AMT_{SSR}$).

Equation 6.2.8.3.6-1: LSE Net Charge

$$\boxed{SSR\_AMT_{LSE} = LSE\_SHARE_{SSR} \times TOTAL\_AMT_{SSR}}$$

6.2.8.4 Example of SSR Cost Allocation

Table 6.2.8.4-1: List of Elemental Pricing Nodes that Impact SSR Constraint

Node	Constraint	Distribution Factor
EP-1	A	0.05
EP-2	A	0.1
EP-3	A	0.08
EP-4	A	0.25
EP-5	A	0.06
EP-6	A	0.15
EP-7	A	0.18
EP-8	A	0.07
EP-9	A	0.3
EP-10	A	0.5
EP-1	B	0.08
EP-2	B	0.1
EP-3	B	0.07
EP-4	B	0.15
EP-5	B	0.18
EP-6	B	0.06
EP-7	B	0.05
EP-8	B	0.3
EP-9	B	0.25

Node	Constraint	Distribution Factor
EP-10	B	0.5
EP-1	C	0.05
EP-2	C	0.5
EP-3	C	0.15
EP-4	C	0.06
EP-5	C	0.07
EP-6	C	0.25
EP-7	C	0.3
EP-8	C	0.08
EP-9	C	0.18
EP-10	C	0.1

Table 6.2.8.4-2: Calculation of Cost Shares by Commercial Pricing Node

EP-Node	CP-Node	Weighting Factor	CP-Node Demand*	EP-CP Demand	Aggregate DF	Aggregate Impact	% cost Allocation
EP-1	CP-1	0.2	100	20	0.18	3.6	0.173652983
EP-2	CP-2	0.2	2000	400	0.7	280	13.50634316
EP-3	CP-3	0.2	1500	300	0.3	90	4.341324586
EP-4	CP-4	0.2	3000	600	0.46	276	13.3133954
EP-5	CP-5	0.2	1000	200	0.31	62	2.990690271
EP-5	CP-6	0.2	5000	1000	0.31	310	14.95345135
EP-6	CP-6	0.2	5000	1000	0.46	460	22.18899233
EP-7	CP-7	0.2	250	50	0.53	26.5	1.278278906
EP-8	CP-8	0.2	1800	360	0.45	162	7.814384255
EP-9	CP-9	0.2	500	100	0.73	73	3.521296609
EP-10	CP-10	0.2	1000	200	1.1	220	10.61212677
EP-10	CP-11	0.2	500	100	1.1	110	5.306063383
Total Impact						2073.1	100

*** CP Node Demand = Monthly coincident peak**

6.2.9 Interconnection Service and Rescission Rights

Generation Resources that are approved to Suspend operation retain interconnection service while the unit is under suspension. The owner of the resource may rescind or modify the dates of the suspension notice at any time. Generator suspension is limited to a maximum of thirty-six (36) Months in a five (5) year period, and failure to return from the generator suspension will result in termination of the interconnection service. Generation Resources that are approved to Retire will lose interconnection service as of the date of the retirement or the end of an SSR Agreement. The owner of the resource may rescind the retirement notice until the time that MISO approves the retirement or terminates the SSR Agreement.

6.2.10 Attachment Y-2 Non-binding Informational Studies

Owners of Generation Resources may submit an Attachment Y-2 request to MISO to perform reliability assessment of the impact of a potential retirement or suspension of their resource without a definitive plan to cease operation. The cost for the study is paid by the requesting owner.

MISO will consult with the ~~affected Transmission Owner(s)~~ Ad Hoc group, *as defined in Section 5.5.1 above,* and perform reliability analysis as described *in the aforementioned Section 6.2.5, above*. The results of the Attachment Y-2 study will be provided to the requesting owner upon completion to aid in Business decisions but will not constitute approval of the change in status or result in an SSR Agreement. Any subsequent definitive decision to Retire or Suspend operation requires the owner to submit a new Attachment Y Notice at least twenty-six (26) weeks in advance of the intended change of status. However, the results from the Attachment Y-2 study may be used to evaluate the subsequent Attachment Y Notice.

7 Cost Allocation Process

Attachment FF, Section III of MISO's EMT presents the Designation of Cost Responsibility for MTEP Projects, which describes the project cost allocation process to all Market Participants and Transmission Customers. The provisions and requirements of the cost allocation process are summarized in the following sections of this Business Practice Manual. Readers and users of this Manual are advised; however, that the authoritative document for project cost allocation remains the Tariff.

7.1 Baseline Reliability Projects

All costs for Baseline Reliability expansion projects are recovered through Attachment O by the Transmission Owner(s) developing such projects.

7.2 Generation Interconnection Projects

Generation Interconnection Projects are Network Upgrades associated with interconnection of new, or increase in generating capacity of existing, generation *under Attachments X to the Tariff*. These projects are driven by interconnection study procedures and agreements. Interconnection Customer is responsible for one-hundred (100%) percent of the costs of Network Upgrades rated below 345 kV and ninety (90%) percent of the costs of Network Upgrades rated at 345 kV and above (with the remaining ten (10%) percent being recovered on a system-wide basis.

7.3 Transmission Delivery Service Projects

Facilities for Transmission Service projects are designated as Direct Assignment or Network Upgrades. Transmission expansion project costs that are designated to Direct Assignment Facilities are allocated to the specific Transmission Customer requesting the service. Costs for Network Upgrade projects are rolled into the MISO facilities rate base until the Transmission Owner is allowed to recover the costs in its own facilities rates.

7.4 Market Efficiency Projects

A Market Efficiency Project can be proposed by MISO, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities and shown to provide market efficiency benefits to one or more Market Participant(s), but not determined to be a Multi-Value Project, and provides sufficient market efficiency benefits to justify inclusion into the MTEP.

The Tariff establishes that an MEP may be eligible for cost sharing as an MTEP transmission expansion project if it has a rated voltage of 230 kV or above, has total project costs of five million dollars ($5 million) or more, and can demonstrate regional benefit metric, multiple future scenarios, and multi-year analysis as described *in Sections 7.4.1 and 7.4.2 below*.

One-hundred (100%) percent of the cost for a Market Efficiency Project is allocated to all Transmission Customers in each of MISO's Cost Allocation Zones (see Attachment WW of the Tariff). The cost allocated to each of these zones is based on the relative benefit each receives from the project, as determined by the economic benefit analysis process described *in Sections 7.4.1 and 7.4.2 below*. Also, a key provision of the cost allocation method is the "No Loss" provision. This "No Loss" provision is intended to protect customers in a zone from being allocated costs where they may not benefit from the project. Zones that are not shown to receive net benefits from the Market Efficiency Project will be excluded from the allocation of the project cost.

If MISO planning staff determines that a specific project meets the criteria of both a Baseline Reliability Project and a Market Efficiency Project, the project cost is allocated using the Market Efficiency Project allocation procedures.

7.4.1 Economic Benefit Metrics

The criteria to determine whether a project should be included as a Market Efficiency Project is based on multiple benefits across multiple future scenarios and multi-year analysis guided by input from all stakeholders. The benefits calculated are described *in Attachment FF-7 of the MISO Tariff* and include the Adjusted Production Cost (APC), Avoided Reliability Project (ARP) Savings and MISO-SPP Settlement Agreement Cost reduction. Each benefit metric is designed to measure a specific value provided by a project. The benefits calculated by each metric are additive, with each benefit tied to its applicable zone (Cost Allocation Zone, Transmission Pricing Zone, and Local Resource Zone) as described below. Total project Benefits = "APC" + "ARP Savings" + "MISO-SPP Settlement Agreement Cost Savings"

7.4.1.1 Adjusted Production Cost

Adjusted production cost (APC) savings will be calculated as the difference in total production cost of the Resources in each Cost Allocation Zone, adjusted for import costs and export revenues, with and without the proposed Market Efficiency Project as part of the Transmission System. Project APC benefit evaluations will 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. The total APC benefit shall be determined by calculating the present value of annual APC benefits for the multiple future scenarios and multi-year evaluations. The weighted futures, no loss (WFNL) metric for each Cost Allocation Zone shall be calculated using the weighted APC savings determined for each future scenario included in the analysis.

7.4.1.2 Avoided Reliability Project Savings

The Avoided Reliability Project (ARP) savings metrics quantifies the savings from one or more reliability projects that are no longer needed as a result of a MEP. The benefit of ARP savings will be the estimated project cost of the ARP converted to the present value of the total annualized cost of the first 20 years of project life after the project in-service date, with a maximum planning horizon of 25 years from the approval year. ARP savings benefits will be allocated to the Transmission Pricing Zone(s) where the reliability project is physically located. Any sunk costs already expended by the Transmission Owner on the reliability project are excluded from the analysis as such costs are not avoided. Sunk costs also include expended costs related to reliability projects that are the same as, or components of, the proposed MEP.

To be eligible, an ARP must be a reliability project recommended for inclusion in Appendix A as the preferred solution to a Transmission Issue in the current planning cycle and be needed after the expected in-service date of the proposed MEP.

7.4.1.3 MISO-SPP Settlement Agreement Cost Savings

The MISO-SPP Settlement Agreement Cost metric directly captures the impact of expected changes in payments pursuant to the capacity-sharing Settlement Agreement among MISO, SPP, and Joint Parties, accepted by the Commission in Docket No. EL14-21, et al., 154 FERC ¶ 61,021 (2016) (“MISO-SPP Settlement Agreement”). This metric accounts not only for potential positive benefits but also for a reduction in benefits due to an increase in payments caused by a proposed MEP.

This metric will be calculated as the future-weighted change in annual payments due from MISO to SPP and the Joint Parties, for MISO flows above the MISO Contract Path Capacity as defined *in Section 2.2 of the Settlement Agreement*, that are attributable to the proposed MEP. All benefits calculated from this metric will be allocated to Local Resource Zones as specified in the MISO-SPP Settlement Agreement and Schedule 49 of the MISO Tariff.

7.4.2 Market Efficiency Project Benefit and Cost Evaluation Methodology

Project benefit evaluations will 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. The annual benefit for a proposed Market Efficiency Project will be determined as the sum of the

APC, ARP and MISO-SPP Settlement reduction benefits, as described *in Section 7.4.1 of this BPM*.

The costs applied in the benefit cost analysis will be the present value, over the same period for which the project benefits are determined, of the annual Network Upgrade Charges for the project as determined in accordance with the formula in Attachment GG for the Transmission Owner constructing the proposed Market Efficiency Project. If the Transmission Owner developing the project is unknown during the planning process (i.e., if the project is eligible for the Competitive Transmission Process), MISO will estimate costs applied in the benefit to cost ratio using professional judgment informed by publicly available information.

The present value calculation for both the annual benefits and annual costs will apply a discount rate representing the after-tax weighted average cost of capital of the Transmission Owner(s) that make up the MISO Transmission System.

A benefit to cost ratio test will be used to evaluate a proposed Market Efficiency Project. Only projects that meet a benefit to cost ratio of 1.25 or greater will be 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 as a percentage of project cost will be determined one time at the time that the project is presented to the MISO Board for approval. Estimated Project Cost will be used to estimate the benefit to cost ratio and the eligibility for cost sharing at the time of project approval. To the extent that the Commission approves the collection of costs in rates for Construction Work in Progress (CWIP) for a constructing Transmission Owner, costs will be allocated and collected prior to completion of the project.

7.5 Multi-Value Projects

The revised Tariff filing of July 15, 2010 incorporated a new type of cost shared project designated as a Multi-Value Project (MVP). An MVP is one or more Network Upgrades that address a common set of Transmission Issues, satisfy one or more of the criteria listed *in Section 7.5.1 of this BPM*, and satisfy all of the conditions listed *in Section 7.5.2 of this BPM*. The primary purpose of the MVP is to enable cost sharing of projects that are regional in nature and developed to enable compliance with public policy requirements, which include state and federal laws and regulations, and/or to provide economic value, defined as the difference between financially quantifiable benefits related to the provision of transmission service and the project costs.

7.5.1 Multi-Value Project Criteria

All Multi-Value Projects must satisfy one or more of the criteria outlined below:

7.5.1.1 Multi-Value Project - Criterion 1

An MVP must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the Transmission System to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

7.5.1.2 Multi-Value Project - Criterion 2

An MVP must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described *in Section 4.3.9 of this BPM*. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value since LMP savings are a subset of production cost savings. The specific types of economic value that may be considered are listed *in Section 7.5.3 of this BPM*.

7.5.1.3 Multi-Value Project - Criterion 3

An MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity reliability standard and must provide economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs. That is, the total MVP Benefit-to-Cost Ratio, as discussed *in Section 4.3.9 of this BPM*, must be greater than 1.0.

7.5.2 Multi-Value Project Conditions

All Multi-Value Projects must satisfy all of the following conditions listed below:

- Must be evaluated as part of a portfolio of projects, as designated in the transmission expansion planning process, whose benefits are spread broadly across the footprint.
- Facilities associated with the transmission project must not be in service, under construction, or approved for construction by the Transmission Provider Board prior to July 16, 2010 or the date the constructing Transmission Owner becomes a signatory Member of the ISO Agreement, whichever is later.
- The transmission project must be evaluated through the MISO planning process and approved for construction by the Transmission Provider Board prior to the start of

construction, where construction does not include preliminary site and route selection activities.

- The transmission project must not contain any transmission facilities listed *in Attachment FF-1 of the Tariff*.
- The total capital cost of the transmission project must be greater than or equal to the lesser of $20,000,000.00 or five (5%) percent of the constructing Transmission Owner's net transmission plant as reported *in Attachment O of the Tariff* at the time the transmission project is approved in an MTEP.
- The transmission project must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV. A transformer is considered to operate above 100 kV when at least two sets of transformer terminals operate at voltages above 100 kV.
- Network Upgrades driven solely by an Interconnection Request, as defined *in Attachment X of the Tariff*, or a Transmission Service request will not be considered MVPs.

7.5.3 Multi-Value Projects - Types of Economic Benefits

The following specific types of economic benefits may be considered when qualifying a project as a Multi-Value Project under Criterion 2 or Criterion 3:

- Production cost savings where production costs include generator startup, hourly generator no-Load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements within specific Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the entire MISO.
- Capacity cost savings due to a reduction of system losses during the system peak demand. Capacity cost savings are generated by reducing the overall resource adequacy requirements by an amount equal to the product of the reduced system loss level during the projected system peak demand and one plus the projected Planning Reserve Margin. The economic value of this reduction will be set equal to the projected value of the Cost of New Entry (CONE).
- Capacity cost savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion. These reductions are typically possible due to relief of transmission congestion and may be determined through execution of Loss of Load Expectation studies.

- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future due to pursuit of a specific MVP.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and directly related to providing Transmission Service. Financially quantifiable benefits not directly related to providing Transmission Service, such as economic development benefits and other types of benefits not directly related to providing Transmission Service, cannot be considered in qualifying a project for MVP status.

7.5.4 Multi-Value Projects - Other Provisions

The following provisions also apply to Multi-Value Projects:

7.5.4.1 Multi-Value Projects - Project Type Designation Rule

Should a project qualify as an MVP and also qualify as either a BRP, MEP, or both, the project will be designated as an MVP and not as a BRP or MEP.

7.5.4.2 Multi-Value Projects - Like-for-Like Capital Replacement

Should a project be required to facilitate like-for-like capital replacements of plant originally installed as part of an MVP where replacement is i) due to aging, failure, damage or relocation requirements and ii) not the result of negligence by the constructing Transmission Owner, that project will be considered an MVP. The minimum project cost limitation for MVPs described *in Section 7.5.2 of this BPM* will not apply to the like-for-like capital replacement projects described in this Section.

7.5.5 **Multi-Value Projects - Cost Allocation**

7.5.5.1 Multi-Value Projects - Qualification of Facilities for Cost Sharing

Subject to the conditions outlined *in Section 7.5.2 of this BPM*, any facility associated with an MVP will qualify for cost sharing subject to the following rules:

- Facilities must be considered Network Upgrades and may include any lower voltage facilities that may be needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the MVP.
- Any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits will not qualify for cost sharing.

- Any DC transmission line and associated terminal equipment will not qualify for cost sharing when scheduling and dispatch of the DC transmission line is not turned over to the MISO markets, real-time control of the DC transmission line is not turned over to the MISO automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service.

7.5.5.2 Multi-Value Projects - Allocation of Eligible Costs

One-hundred (100%) percent of the eligible annual revenue requirements of the MVPs shall be allocated on a system-wide basis to Transmission Customers that withdraw energy, including both Loads internal to the MISO footprint and External Transactions sinking outside the MISO footprint, excluding transactions that sink in PJM. Also, Load serviced under a Grandfather Agreement is excluded from charges for MVPs. The allocation of costs will be in proportion to the metered energy in MWh withdrawn from the Transmission System for internal Loads or the energy in MWh scheduled for External Transactions. Eligibility of annual revenue requirements for cost sharing is in accordance *with Section 7.5.5.1 of this BPM*. These annual revenue requirements will be recovered through a MVP Usage Charge which is described in more detail *in BPM-005 – Market Settlements*. Revenues collected through this charge will be distributed to the Transmission Owner(s) in accordance with the ISO agreement.

7.6 Targeted Market Efficiency Projects

Targeted Market Efficiency Projects are interregionally cost allocated with PJM *under Section 9.4 of the MISO-PJM Joint Operating Agreement*. The MISO share of the project cost is allocated to benefiting Transmission Pricing Zones in accordance *with Attachment FF of the MISO Tariff*.

7.7 Project Completion Reporting Guidelines – for Cost Shared Projects

Transmission Owner(s) shall report the MTEP approved cost shared projects (i.e., BRP[30], GIP, MEP, TMEP and MVP) upon completion and commissioning of those projects to MISO. This information will be used to verify that only the costs of approved cost shared projects and facilities are charged to other pricing zones through Attachment GG (BRP, GIP, TMEP and MEP) and Attachment MM (MVP) revenue requirement and rates calculations. Also, the information will be

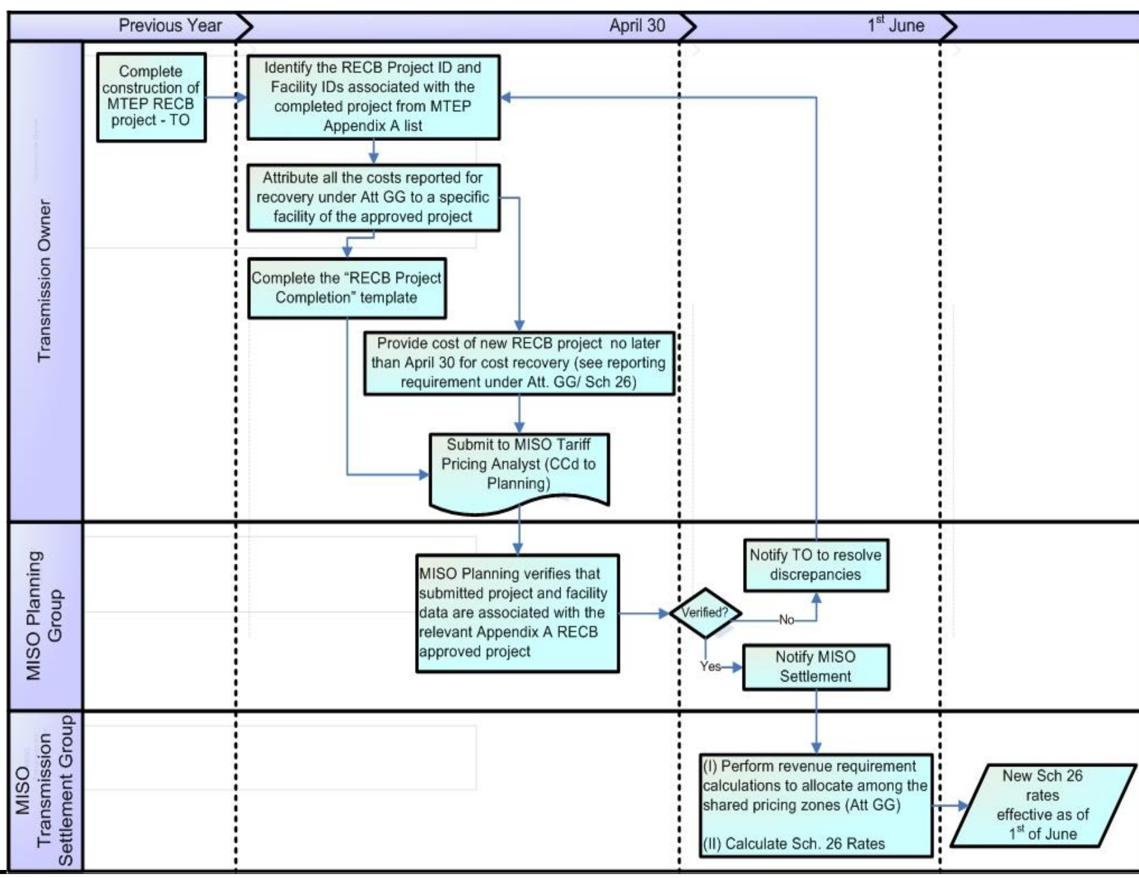
[30] Applies to Baseline Reliability Projects approved by the MISO Board of Directors for cost sharing before MTEP13.

used for the purpose of tracking costs and in-service dates of approved MTEP cost shared projects.

This reporting requirement supplements the annual reporting requirements under Attachment GG and Attachment MM of the Tariff for calculating and collecting the charges associated with Network Upgrades of cost shared projects and for distributing the revenues associated with such charges. Figure 7.7-1 below, shows a high-level process flow diagram with a time-line and associated responsibilities.

A reporting template along with the appropriate contact and submittal information is posted on the Planning page of the MISO web site (MISO Planning). This template shall also be used for reporting Construction Work In Progress (CWIP) costs associated with MTEP-approved cost shared projects for cost recovery through Attachment GG and Attachment MM of the Tariff by Transmission Owner(s) with FERC approval for recovery of CWIP costs.

Figure 7.7-1: Process Flow for Reporting MTEP Cost Shared Project Costs for Recovery under Attachment GG and MM of the Tariff



Note: (1) For certain Transmission Owner(s) (ATC LLC, ITC/METC) who have forward-looking formula rates, the Schedule 26 rates' effective date will be January 1st, requiring a Nov 30th Attachment GG reporting date to MISO. Also, the project costs could include MTEP cost shared project costs projected for the following year.

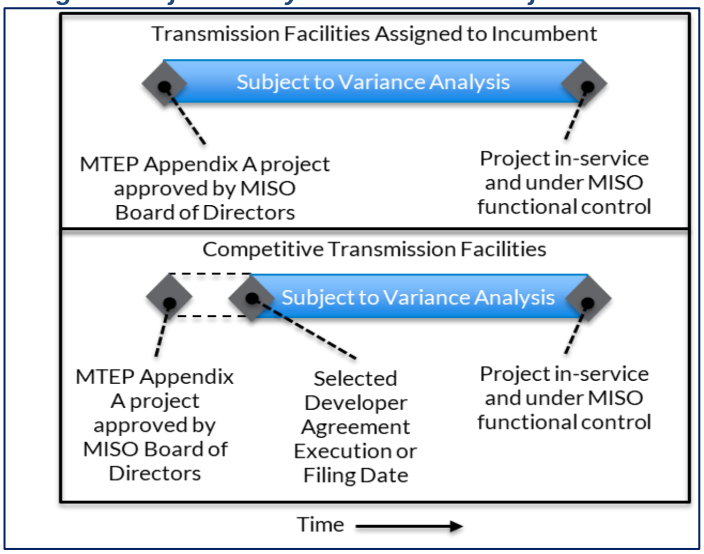
8 Variance Analysis

After a MTEP is approved by the MISO Board of Directors, certain circumstances or events may arise that could potentially have a material impact on approved facilities, triggering MISO's Variance Analysis process. Variance Analysis is the additional analysis performed by MISO to understand the reasons for such circumstances or events and to evaluate the potential impacts that these circumstances or events may have on the applicable project and the Transmission System.

8.1 Applicability and Scope

MISO's Variance Analysis process is applicable to Eligible Projects and the facilities that comprise such projects approved by the MISO Board of Directors for inclusion in Appendix A of the MTEP after December 1, 2015, *in accordance with Section IX.A of Attachment FF of the MISO Tariff*. Eligible Projects and their component facilities are subject to the Variance Analysis process at different times depending on whether their development is assigned to incumbent Transmission Owner(s) or awarded through the Competitive Transmission Process.

Figure 8.1-1: Eligible Project Lifecycle and When Subject to Variance Analysis



MISO monitors the quarterly facility status updates submitted by Transmission Owners and/or Selected Developers, and other available information to determine if a ground may exist to conduct Variance Analysis for an Eligible Project or one of its individual facilities.

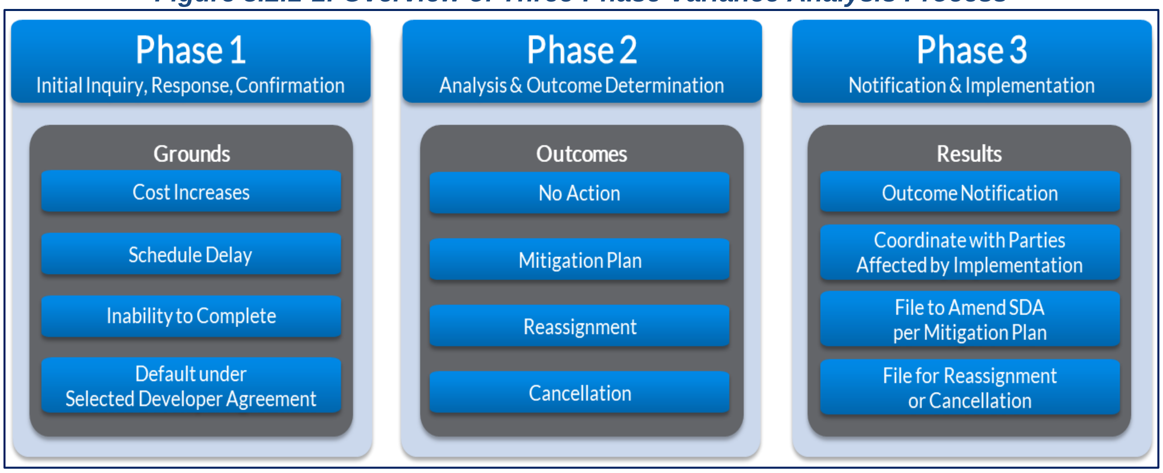
8.2 Variance Analysis Process

The process that will be utilized by MISO to perform a Variance Analysis is detailed *in this Section 8 of BPM-020 and governed by the MISO Tariff in Section IX of Attachment FF*.

8.2.1 Three Phase Variance Analysis

Variance Analysis is a sequential, methodical, three-phase process that is based on identifying and confirming Variance Analysis grounds (phase 1), conducting analysis to determine the appropriate outcome (phase 2), and implementation of the outcome selected (phase 3).

Figure 8.2.1-1: Overview of Three-Phase Variance Analysis Process



There are four main grounds that may trigger the commencement of Variance Analysis. These four grounds are specified *in Section IX.C of Attachment FF of the MISO Tariff*. Phase 1 is the process for confirming whether one or more identified grounds for commencing Variance Analysis exist.

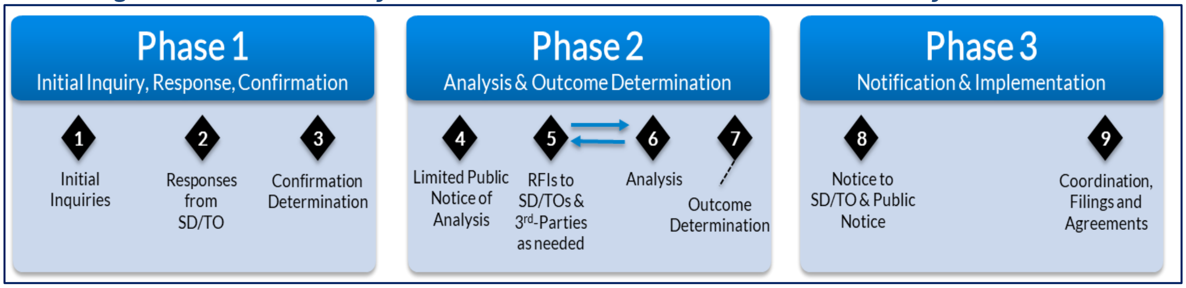
There are four types of outcomes of the Variance Analysis process. These outcomes are described *in Section IX.E of Attachment FF of the MISO Tariff*. Phase 2 involves a process of data collection and analysis for the purpose of selecting the appropriate outcome for confirmed Variance Analysis grounds.

The results of the Variance Analysis process depend on the outcome selected and whether the project is a Competitive Transmission Project (requiring a Selected Developer Agreement) or assigned to the incumbent Transmission Owner(s). Phase 3 consists of implementing the outcome that was selected in phase 2.

8.2.2 Activities and Milestones

Generally, the Variance Analysis process consists of approximately nine activities and milestones.

Figure 8.2.2-1: Nine Key Activities and Milestones in Variance Analysis Process

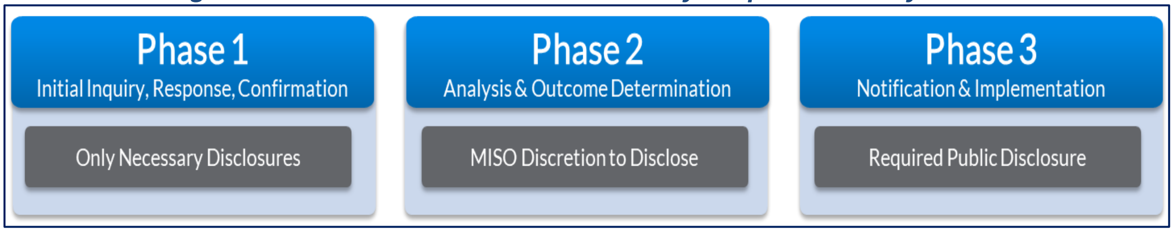


The nine activities and milestones *shown in Figure 8.2.2-1* are the tactical steps to move through the process from one phase to the next. The order and timing of key activities and milestones may be tailored to the needs of individual projects or instances of Variance Analysis. For example, in more complex Variance Analyses. MISO may determine that subsequent inquiries and further responses from the applicable Selected Developer or Transmission Owner are required. The applicable Selected Developer or Transmission Owner will be given an opportunity to be heard during the process at an appropriate, mutually-agreed, time.

8.2.3 Confidentiality Requirements of Variance Analysis by Phase

The specific confidentiality provisions applicable to the Variance Analysis process are described *in Section IX.F of Attachment FF of the MISO Tariff*.

Figure 8.2.3-1: Overview of Confidentiality Requirements by Phase



As illustrated in Figure 8.2.3-1, confidentiality requirements are most restrictive in phase 1 and ease at the end of phase 3. In phase 1, public disclosure of whether Variance Analysis has commenced is not permitted. In phase 2, MISO has discretion to post limited public notice stating only that Variance Analysis has commenced for a particular facility or project and the grounds found to exist. In phase 3, MISO is required to post a public notice of the Variance Analysis outcome that was selected. MISO is permitted by its Tariff to disclose that Variance Analysis has commenced to third parties if it is necessary to request information in phases 1 and 2 to establish the existence of ground(s) or to collect information to evaluate possible outcomes.

8.2.4 Duration of Variance Analysis phases

The durations of phases 1, 2, and 3 of Variance Analysis are neither defined nor limited *by the MISO Tariff or this BPM*. This allows Variance Analysis to be effectively applied to broad range of scenarios.

8.2.5 Governance of Variance Analysis

The Competitive Transmission Executive Committee has the exclusive and final authority to oversee and implement Variance Analysis, including the decision to implement any of the appropriate Variance Analysis outcomes. Specific provisions applicable to the governance of Variance Analysis can be found *in Section IX.B of Attachment FF of the MISO Tariff*.

8.2.6 Phase 1: Initial Inquiry, Response, Confirmation

Variance Analysis will commence with an initial inquiry (or inquiries) when MISO determines that one or more of the grounds for Variance Analysis[31] may exist *in accordance with Section IX.D of Attachment FF of the MISO Tariff*. Upon such determination, MISO will send an email notification to the applicable Selected Developer(s) or Transmission Owner(s) that Variance Analysis has been triggered. This email notification will be sent to the primary and secondary contact persons that the Selected Developer(s) or Transmission Owner(s) have on file with MISO through their project status reporting submissions that are required *in accordance with Section 4.2.3.1 of this BPM* and shall include a brief description of MISO's concerns. This initial inquiry is represented as activity/milestone #1 *in Figure 8.2.2-1*.

In accordance with Section IX.D.1 of Attachment FF of the MISO Tariff, the applicable Selected Developer(s) or Transmission Owner(s) shall have an opportunity to state its position on whether the grounds for triggering a Variance Analysis described in the initial inquiry notification exist and what Variance Analysis outcome it believes is appropriate for the respective situation. Supporting facts and documentation shall be submitted by the applicable Selected Developer(s) or Transmission Owner(s) to MISO as part of the Selected Developer(s) or Transmission Owner(s) response. Submission of this response or responses on position and the supporting facts and documentation are represented as activity/milestone #2 *in Figure 8.2.2-1*.

Based upon a consideration of the Selected Developer(s) or Transmission Owner(s) response(s) and any other relevant information, MISO will determine whether it continues to believe grounds

[31] The grounds for Variance Analysis are specified by the MISO Tariff in *Section IX.C of Attachment FF*

for triggering Variance Analysis exist. Should MISO determine that the grounds for Variance Analysis do not exist, it shall terminate the instance of Variance Analysis. If MISO continues to believe that reasonable grounds for Variance Analysis still exist, it will confirm that the grounds exist and commence Phase 2 of Variance Analysis. MISO will notify the applicable Selected Developer(s) or Transmission Owner(s) of its determination by email through their respective primary and secondary contact persons on file with MISO through their project status reporting submissions required *in accordance with Section 4.2.3.1 of this BPM*. Confirmation that grounds exist or that they do not exist and that, therefore, Variance Analysis should be terminated are both represented by activity/milestone #3 *in Figure 8.2.2-1*.

8.2.7 Phase 2: Analysis and Outcome Determination

At the beginning of phase 2, *in accordance with Section IX.F of Attachment FF of the MISO Tariff*, MISO may elect, but is not required, to provide limited public notice that Variance Analysis has commenced once it has confirmed that one or more grounds exist. This public notice will be posted on the MISO website.[32] Public notice that Variance Analysis has commenced is represented as activity/milestone #4 *in Figure 8.2.2-1*.

Once MISO confirms grounds for Variance Analysis exist, MISO will further evaluate the circumstances, events, and relevant facts associated with the Variance Analysis scope in accordance with the provisions specified *by Section IX.D.2 of Attachment FF of the MISO Tariff*. MISO will collect 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. The repeatable data collection and analysis process is represented as activities/milestones #5 and #6 *in Figure 8.2.2-1*.

Upon completion of its analysis, the CTEC may make a determination as to which Variance Analysis outcome to apply in accordance with the MISO Tariff, *as described in Sections IX.D.2 and IX.D.2.1 of Attachment FF of the MISO Tariff*. The possible outcomes of a Variance Analysis are *specified under Section IX.E of Attachment FF of the MISO Tariff*. Further selection considerations for each individual outcome are listed *in Sections IX.E.1, IX.E.2, IX.E.3, and IX.E.4 of Attachment FF of the MISO Tariff*. The ultimate outcome determination that marks the end of phase 2 is represented as activity/milestone #7 *in Figure 8.2.2-1*.

[32] https://www.misoenergy.org/planning/planning/

8.2.8 Phase 3: Notification and Implementation

In accordance with Section IX.D.3 of Attachment FF of the MISO Tariff, MISO will inform the applicable Selected Developer(s), Transmission Owner(s), and any other affected parties of the selected Variance Analysis outcome. Such notification will be sent by email to the respective primary and secondary contact persons on file with MISO through their project status reporting submissions required *in accordance with Section 4.2.3.1 of this BPM*. Public notice will be posted on the MISO website, as soon as practicable after notifying the applicable Selected Developer(s) or Transmission Owner(s) and any other affected parties of the Variance Analysis outcome. The posting shall include the reason(s) the respective Variance Analysis outcome was selected. Both the notifications to affected parties and the public postings shall be appropriately redacted in order to protect any Critical Energy Infrastructure Information (CEII) and any Confidential Information not needed to explain why Variance Analysis was triggered or why a particular outcome was selected *in accordance with Section IX.D.3.B of Attachment FF of the MISO Tariff*. The notice provided to applicable Selected Developer(s), Transmission Owner(s), and any other affected parties, in addition to the public notice posted to the website are represented together as activity/milestone #8 *in Figure 8.2.2-1*.

In accordance with Section IX.D.3 of Attachment FF of the MISO Tariff, 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 applicable Selected Developer(s) shall 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 Competitive Transmission Facility, MISO will file a Notice of Termination with the FERC in accordance with the provisions *specified in Section IX.D.3.E of Attachment FF of the MISO Tariff*. The implementation of the selected Variance Analysis outcome, including but not limited to coordination among affected parties and the filing of agreements and notices, is represented as activity/milestone #9 *in Figure 8.2.2-1*.

8.3 Project Financial Security Impacts due to Variance Analysis

The potential impacts on a Selected Developer's Project Financial Security as a result of a Variance Analysis are *specified in Section IX.H of Attachment FF of the MISO Tariff*.

8.4 Dispute Resolution Provisions for Variance Analysis

Disputes associated with the Variance Analysis process shall be addressed in accordance with the provisions *specified in Section IX.G of Attachment FF of the MISO Tariff*.

Appendix A Planning for Electric Storage Facilities

Definition: Storage As Transmission-Only Asset (SATOA)

An electric storage facility that is connected or proposed to be connected to the Transmission System through inclusion in Appendix A of the MTEP, as a transmission facility that is part of the Transmission System, that is capable of receiving energy from the Transmission System and storing energy for injection to the Transmission System, and is operated only to support the Transmission System. An electric storage facility may qualify as a SATOA if it meets the MISO Tariff criteria for a SATOA.[33] A storage facility will not be evaluated as a potential SATOA to resolve a routine (i.e., N-0 or N-1) Transmission Issue that can be addressed by a market solution. Storage facilities may be proposed in Appendix B of the MTEP, and MISO will evaluate if they qualify as a SATOA in the MTEP cycle for which its proposed to move to Appendix A of the MTEP.

A.1 Modeling Storage As Transmission-Only Asset (SATOA)

Electric storage facilities being proposed as SATOAs for inclusion in MTEP as a solution to a Transmission Issue in the current MTEP cycle will be represented in the power flow models as a pseudo generator that is not connected to operate except to address the identified Transmission Issue. It will have an ID of “TA” for transmission asset. This will facilitate identification of the device in the models. In each case where such projects meet these requirements, MISO planning staff will model each SATOA consistent with the operation(s) it was approved for in MTEP.

A.2 SATOA Approved in Prior MTEP Cycles

SATOAs approved in prior MTEP cycles will be assumed to be available for operation in the current MTEP cycle to address the Transmission Issue(s) the SATOA was approved for when the SATOA was included in MTEP. If a SATOA approved in a prior MTEP cycle is to be evaluated in the current MTEP cycle to resolve a newly identified Transmission Issue, it will have to meet all the SATOA requirements for the newly identified Transmission Issue and it has to continue to be able to resolve the Transmission Issue it was selected for in prior MTEP cycles. Further, a SATOA approved in a prior MTEP cycle as one transmission project type, could be considered to resolve the newly identified Transmission Issues of any transmission project type. Any additional project costs to modify the SATOA approved in a prior MTEP cycle to resolve the newly identified

[33] *See* MISO Tariff, Attachment FF, Section II.G.

Transmission Issue in the current MTEP cycle (while still being able to resolve the Transmission Issue the SATOA was selected for in prior MTEP cycles) will be allocated to the project type associated with the new Transmission Issue identified in the current MTEP cycle.

A.3 SATOA Proposed in the Current MTEP Cycle

A SATOA may be any one of the transmission project types described *in Sections II.A through II.D and II.F of Attachment FF of the MISO Tariff* that meet the definitions, criteria, or factors applicable to those project types. For example, where an electric storage facility is proposed as a SATOA to be evaluated as an economic transmission project, it will be evaluated the same as any other economic transmission project in terms of eligibility, benefit calculation, qualification for approval, and cost allocation. A SATOA is eligible for cost recovery consistent with the cost recovery for its project type under Attachment FF, including cost recovery *under Section III.A.2.k of Attachment FF of the MISO Tariff*.

SATOA proposals for any transmission project type must also include specifications of the proposed project as requested in the SATOA eligibility checklist form and the SATOA life cycle cost estimate spreadsheet, and any other details that would aid in accurate modeling of the electric storage facility. Additionally, proposals must specify which Transmission Issue(s) will be resolved by the proposed SATOA and a description of how the electric storage facility will be operated to resolve the Transmission Issue(s).

MISO will evaluate the appropriateness of an electric storage facility proposed as a SATOA for any project transmission type to solve Transmission Issues comparably to any other transmission (wires) solution. Considerations will include:

- Ability of the facility to address the Transmission Issue (e.g., loading, voltage, stability) in all hours that the Transmission Issue is identified to exist.
- The minimum and maximum capacity required to address the Transmission Issue to ensure that excess storage capacity is not treated as a transmission only asset.
- Assurance of sufficient energy and/or reactive capability (MWh/MVAr) to charge or discharge for the period identified as necessary in the planning study.
- Life-cycle cost comparisons including consideration of the period that is required to address the Transmission Issue identified in the planning study, which may be less than the life cycle of alternatives. This shall include but not be limited to the life cycle of a SATOA and certain equipment that may need to be replaced or augmented during shorter time spans than the overall life span of the project consistent *with Section A.3.1 below.*

- Additional considerations that may support comparative evaluation among various solution alternatives, such as lead-time to develop, right of way or substation impacts, expandability, operational flexibility, system capacity, or others.

In order to propose an electric storage facility as a SATOA in the current MTEP cycle, the following must be completed:

- A SATOA eligibility checklist form (.docx Word document) – can be found on MISO website at: MISO Transmission Planning
- A SATOA Life Cycle cost estimate (.xlsx Excel spreadsheet) – can be found on MISO website at: MISO Transmission Planning
- A PSCAD model for the proposed SATOA must be provided if proposed for inclusion in Appendix A of MTEP
- Any third-party studies that helped evaluate the proposed SATOA

The eligibility checklist form and life cycle cost estimate must be sent to MISO Expansion Planning on or before Sept. 15th of the current MTEP cycle if facility is proposed as a reliability project or must be submitted during a solution submission window. The email address of where to send the forms are included in the forms themselves.

A.3.1 Life Cycle Cost Estimates

Selection of the electric storage facility as a SATOA as the preferred transmission solution in MTEP will consider similar cost and effectiveness considerations applied to any other transmission solution. Life cycle cost estimates are provided in nominal dollars for every year in the period the SATOA project is being considered. When an electric storage facility is proposed as a SATOA, the proposal will include the estimated life cycle costs for both the SATOA and other transmission alternatives:

- The direct capital cost of the facility;

- The expected useful life of the facility (the same number of years must be estimated for the SATOA and other transmission alternatives to allow for a comparison of estimated costs);

- Equipment replacement schedules and associated life-costs and other ongoing costs to maintain the facility at its required capacity and energy capability necessary for a life cycle that is required to address the Transmission Issue identified, or otherwise comparable to a traditional wires solution. Include supporting study information and/or publicly available research to support equipment replacement cost estimates;

- Other cost and performance information as MISO may determine is necessary to compare cost and performance with other proposed solutions to the Transmission Issue identified.

A.3.2 Electromagnetic Transient (EMT) Model Requirements

At the beginning of the MTEP cycle, MISO will identify SATOA projects, as defined in Module A of the MISO Tariff, proposed for inclusion in Appendix A of the MTEP cycle. The submission of the PSCAD models for SATOA projects is required for any Appendix A project that is proposed in the MTEP cycle.

For electric storage facilities that are proposed as potential SATOA projects in Appendix B of the MTEP cycle, the PSCAD models will not be required immediately; however, PSCAD models submission will be required as detailed in the next paragraph, if SATOA projects move from Appendix B to Appendix A during the MTEP cycle. The PSCAD models shall have parameters consistent with the PSS®E Library dynamics models to be submitted for dynamic-stability analyses for the MTEP cycle.

SATOA projects submitted for inclusion in Appendix A of MTEP will be required to submit a PSCAD model of the entire project by the second Subregional Planning Meeting of the current MTEP cycle. The submission shall include any STATCOM, D-VAR, SVC or other applicable equipment, proposed to supplement the SATOA, and located at the same site. The provided PSCAD model shall comply with the PSCAD Model Requirements Supplier Checklist located at: Extranix.

The PSCAD models must be updated to reflect any changes that are made to the proposed SATOA during the MTEP cycle. Also, during the information exchange period of the MTEP, MISO will request any changes for identified SATOAs in the PSCAD models for previously approved SATOA projects. The purpose of this is to allow MISO and Transmission Owners to readily include PSCAD models in any detailed PSCAD studies of the area near SATOA projects and to mitigate any potential delays in planning studies.

Local Planning Criteria in combination with MISOs evaluation will be followed to determine the need for a detailed EMT study of individual SATOA-solutions in MTEP annual planning studies.

A.3.2.1 Inverter-based Reliability Analysis

Each SATOA shall undergo assessment of system reliability impacts for when it operates applicable to inverter-based facilities on the same basis and in a manner comparable to such analysis in the Generator Interconnection Procedures applicable to storage Resources as inverter-based facilities.

Each SATOA must adhere to the requirements set forth in the latest effective version of NERC PRC-024[34] which is applicable to asset owners. This determines the ability of the resource to remain connected to the electric grid during defined frequency and voltage excursions. Planning analysis will determine the need for SATOA to be able to ride through such excursions.

A.3.3 Selection of SATOA as a Preferred Solution in MTEP

For an electric storage facility to be selected as a SATOA for inclusion in MTEP as the preferred solution compared to other transmission line alternatives, the SATOA must be demonstrated through the planning process to:

- Address the identified Transmission Issue for the period identified as necessary in the planning study with a life cycle cost that is comparable to other potential transmission solutions.
- Address the Transmission Issue after consideration of the comparability in system performance to other transmission solutions and any proposed non-transmission alternatives *in accordance with section 4.3.1.2 of this BPM*.
- Have unique characteristics compared to other potential solutions when considering any uncertainties associated with such selections including but not limited to:

[34] **PRC-024: Generator Frequency and Voltage Protective Relay Settings** - Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

- Speed of operation – for example, a SATOA may have an extremely fast discharge capability that makes it uniquely positioned to resolve the identified Transmission Issue more quickly than any other transmission technology
- Lead-time to implement – for example, a SATOA may be able to be implemented in a shorter time span than other transmission technologies with longer lead times
- Right-of-way or other property considerations – for example, a SATOA may be able to be installed in an existing substation which could reduce the complexity of the permitting process versus a transmission line alternative

A.3.4 Transmission upgrades required as a result of SATOA impacts on resources in the Interconnection Queue

In addition to the considerations *in section A.3.3*. for selection as a recommended transmission project for MTEP, if MISO or a stakeholder identifies a potential impact to increase network upgrades costs to Generating Facilities in the Definitive Planning Phase pursuant to Attachment X, MISO will assess whether there is any impact from the proposed SATOA to those Generating Facilities in the Definitive Planning Phase. MISO will identify those Generation Facilities in proximity of the SATOA in the MTEP model that have the potential to be impacted to compare loading impacts with or without the SATOA operating in the manner required for the SATOA to address the Transmission Issue identified for the SATOA to resolve. Generation Facilities in the Definitive Planning Phases that are included in the assessment will be dispatched consistent with the MTEP models and MISO's Model Data Requirements and Reporting Procedures. Generation Facilities included in the assessment will be notified from MISO at the applicable Subregional Planning Meeting when the assessment occurs. If the assessment demonstrates the need for additional system mitigation (i.e., additional network upgrades), the cost of that mitigation will be included in the evaluation of the proposed SATOA compared to other potential solutions and will be included as part of the SATOA project. No network upgrades resulting from impacts of the SATOA project would be assigned to any Generation Facilities in the Definitive Planning Phases.

A.4 Development of Operating Guides Associated with SATOA Selection for MTEP

The selection of an electric storage facility as a SATOA to be included in MTEP as a transmission project that adheres to the provisions of Attachment FF in determining the project type (BRP, MEP, GI, Other, etc.), shall have the cost allocation and eligibility to construct that is associated with that project type. Operation of the asset in real-time should be consistent with these determinations while allowing that the asset should be deployed as needed for the identified Transmission Issue. Upon inclusion of the SATOA in Appendix A of MTEP, MISO will work the TOP on the creation of the Operating Guide that reflects the operating requirements planned for in MTEP. During the MTEP planning process, MISO will develop with Stakeholders the parameters that the SATOA can be used for in operations – these parameters will be the basis for the Operating Guide that is further developed upon Project approval.

A.5 Retirement of SATOA

No SATOA may be retired from service permanently unless the retirement is submitted into the annual MTEP planning process as a proposed project retirement, reviewed by MISO for its impact on Transmission System performance, and accepted by MISO based on such review. Stakeholders will be notified of MISO's assessment of a proposed SATOA retirement when it occurs at the applicable Subregional Planning Meeting.

A.5.1. Retired SATOA

Any SATOA facility that has retired as a transmission asset and desires to operate as a resource must also obtain a Generator Interconnection Agreement to operate and follow the MISO Generator Interconnection Procedures and any market participation requirements.

Appendix B TSR Planning Guideline No. 1.2 – SIS Report Format

Purpose

To provide guidelines for consistent reporting of System Impact Studies associated with requests for long-term firm transmission service under the Tariff.

Introduction

This guideline is to be followed by MISO planning staff, Transmission Owner(s), or Third Parties when reporting results of an SIS in order to provide consistency in the reporting of results for such studies.

Report Outline

The SIS report shall include the following information:

Executive Summary

This section lists:

- Type of service requested
- Whether or not service can be granted at this time
  - Profile of service, if applicable
  - List of milestones for the profile
  - List (or point to a list) of transmission system constraints
  - Cost to resolve the constraints to service
  - If there is existing SPS to mitigate the constraints, then the MW reduction of the existing SPS does not exceed its maximum allowable run back with additional transfer.

Description of Request

The OASIS request information identifying the transaction.

Criteria, Methodology, and Assumptions

A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities.

Analysis Results

A summary of results of any thermal, voltage, and stability analyses conducted indicating the impact of the request on system performance. Analysis output will be retained and be available for review.

Preliminary Estimate if Direct Assignment or Network Upgrades Required

A listing of any Direct Assignment or Network Upgrade facilities preliminarily determined to be necessary to accommodate the request. A good faith estimate of the customer cost responsibility for such facilities will be determined in a subsequent Facilities Study

Appendix C TSR Planning Guideline No. 1.3 – FS Report Format

Purpose

To provide guidelines for consistent reporting of Facility Studies associated with requests for long-term firm transmission service under the Tariff.

Introduction

This guideline is to be followed by MISO planning staff, Transmission Owner(s), or Third Parties when reporting results of a Facility Study in order to provide consistency in the reporting of results of such studies.

Report Outline

The Facility Study report shall include the following information:

Description of Request

The OASIS request information identifying the transaction.

Criteria, Methodology, and Assumptions

A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities. A description of the new/upgrade facilities.

Good Faith Estimate

A detailed statement of the cost of any Direct Assignment Facilities to be charged to the Transmission Customer, the Transmission Customer's appropriate share of the cost of any required Network Upgrades, and the time required to complete such construction and initiate the requested service.

Appendix D Long-term Firm Transmission Service Requests – Process Overview

Figure D-1: Long Term Transmission Service Requests Process Overview (Steps 1-11)

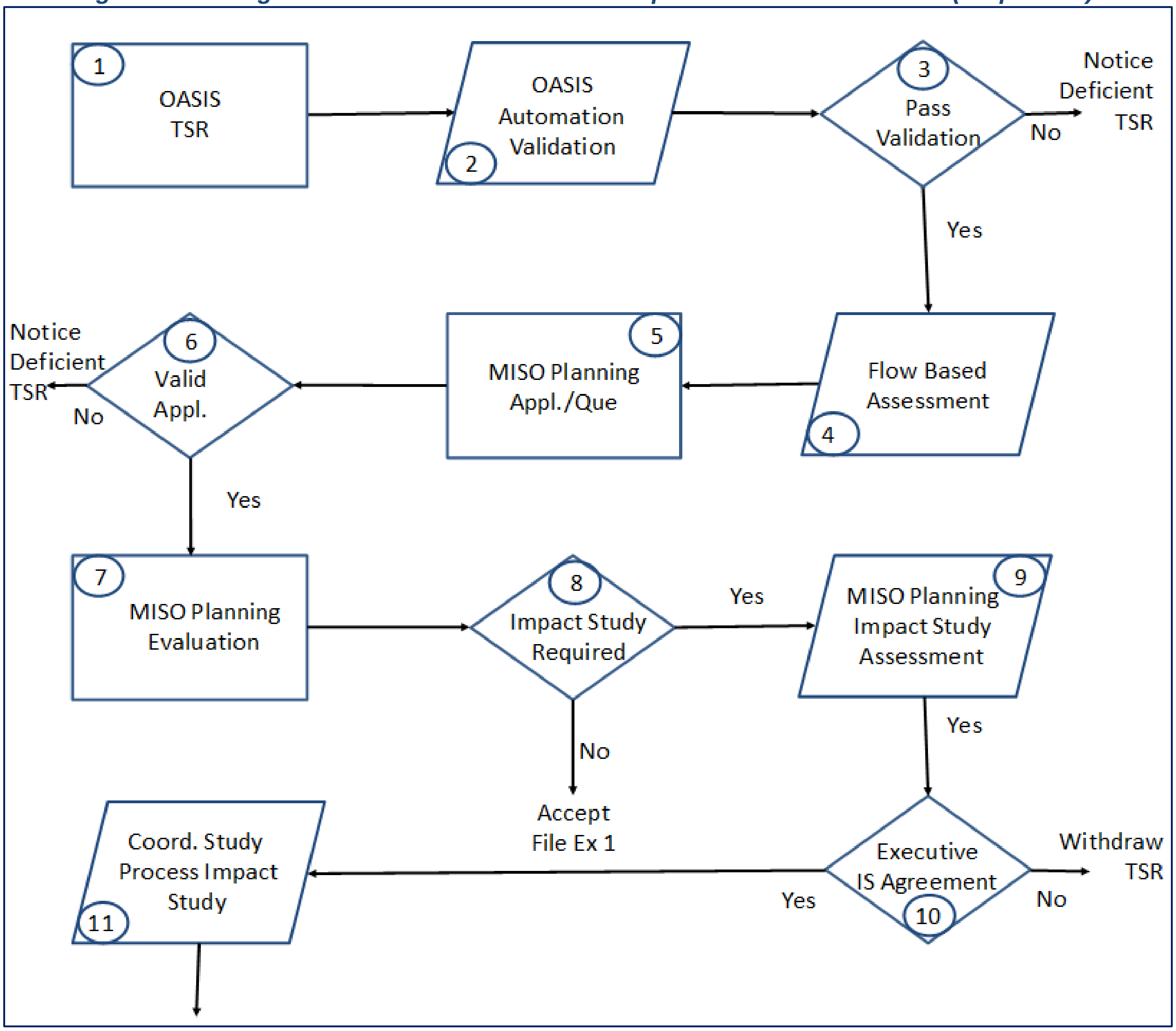
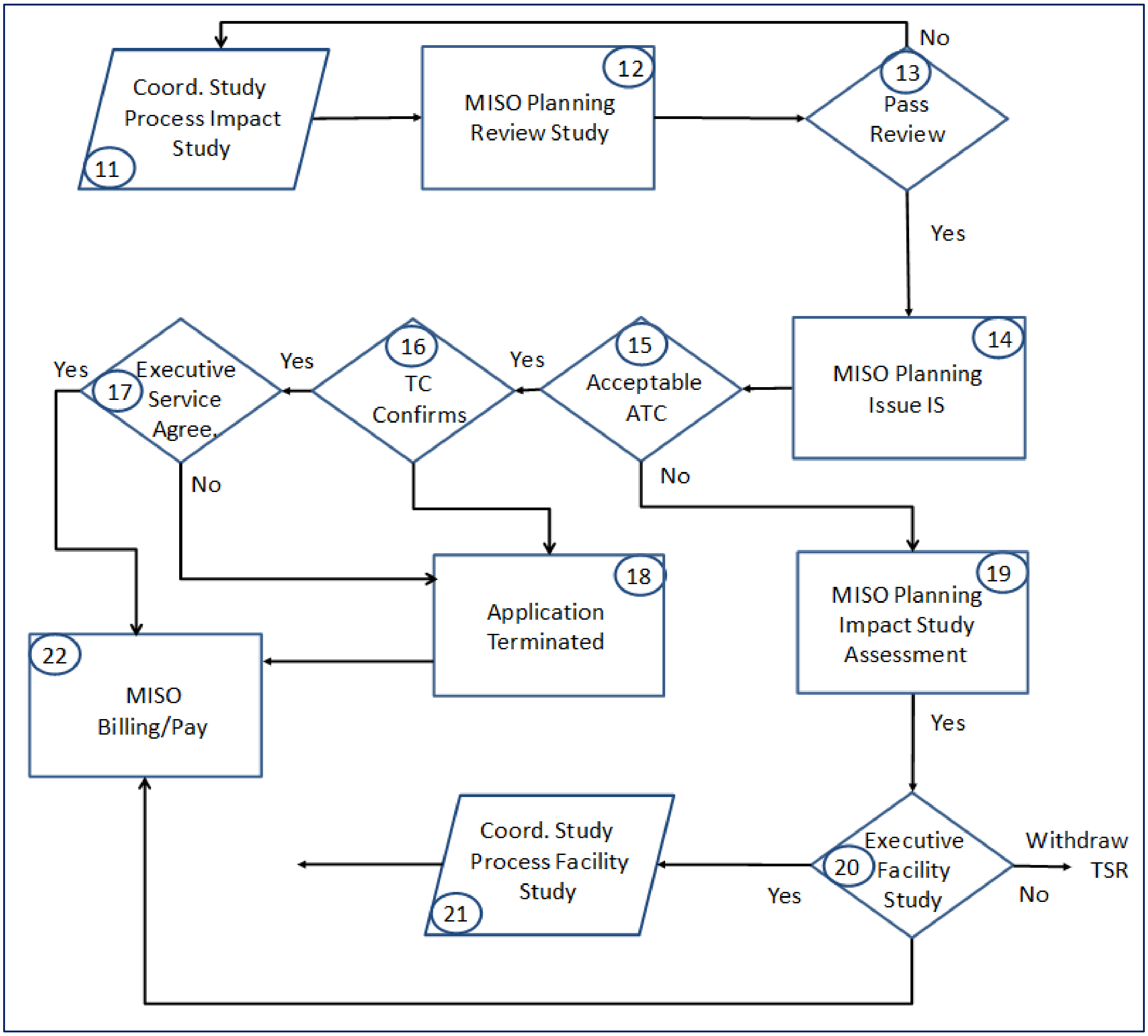


Figure D-2: Long Term Transmission Service Requests Process Overview (Steps 11-22)



Appendix E Universal Planning Non-Disclosure and Confidentiality Agreement for Sector Members

UNIVERSAL PLANNING NON-DISCLOSURE AND CONFIDENTIALITY AGREEMENT FOR SECTOR MEMBERS

This Universal Planning Non-Disclosure and Confidentiality Agreement for Sector Members (the "Agreement") is entered into by and between the Midcontinent Independent System Operator, Inc. ("MISO") and ______________________________, ("Sector Member") whose principal offices are located at ___________________________________. MISO and Sector Member each may be referred to individually as a "Party" or collectively as the "Parties." The effective date ("Effective Date") of this Agreement is the last date shown for execution by each of the Parties.

WHEREAS, MISO is prepared to disclose Confidential/CEII data under this Agreement to Sector Member that participates in an Advisory Committee sector in connection with provisions in Attachment FF of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") relating to the disclosure of information used to develop the MISO Transmission Plan and Sector Member's corresponding use of the data for that planning;

WHEREAS, Sector Member represents that it desires to receive Confidential/CEII data pursuant to this Agreement; and,

WHEREAS, MISO and Sector Member desire to set forth in writing the terms and conditions of their agreement.

NOW THEREFORE, in consideration of the mutual promises, covenants, representations and agreements contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. **Definitions - For purposes of this Agreement.**

   a. "Confidential Information," as used in this Agreement, means all information disclosed to Sector Member by MISO or its employees, agents, contractors, representatives, consultants and advisors (collectively "Disclosing Party") in connection with the Purpose. Confidential Information includes, without limitation, (i) any and all business, technical, marketing, financial or other information, whether in electronic, oral or written form; (ii) trade secrets, business plans, techniques, methods, or systems, data, know-how, formulae, compositions, designs, sketches, mock-ups, prototypes, photographs, charts, graphs, forms, documents, drawings, samples, inventions, ideas, research and development, customer and vendor lists (including, without limitation, the identity, characteristics, contact persons, product and service needs thereof), rates, price lists, computer software programs and systems, financial statements, and budgets; (iii) all memoranda, summaries, notes, analyses, compilations, studies or those portions of other documents prepared by Sector Member to the extent they contain or reflect such information of, or the contents of discussions with the Disclosing Party (“Comingled Material"), including the contents or existence of discussions or negotiations related to the Purpose; (iv) information not generally known or readily ascertainable; (v) information that provides a competitive advantage for Disclosing Party; and (vi) information that is marked “Confidential” or nonpublic information which under the circumstances surrounding disclosure a reasonable person would conclude should be treated as confidential. Confidential Information shall not include information that (a) is or becomes part of the public domain other than as a result of disclosure by Sector Member, (b) becomes available to Sector Member on a non-confidential basis from a source other than Disclosing Party, provided that, to the best of Sector Member’s knowledge, such source is not prohibited from transmitting such information by a contractual, legal, or other obligation, or (c) was in Sector Member’s possession prior to disclosure of the same by Disclosing Party.

b. The term “CEII” shall include specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that: (1) relates details about the production, generation, transportation, transmission, or distribution of energy; (2) could be useful to a person in planning an attack on critical infrastructure; (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552 (2000); and (4) does not simply give the general location of the critical infrastructure. Narratives such as the descriptions of facilities and processes are generally not CEII unless they describe specific engineering and design details of critical infrastructure.

c. “Confidential/CEII data” is a term that recognizes that CEII is normally included in the contents of disclosures related to the Purpose. The terms of this Agreement shall apply equally to all information disclosed in connection with the Purpose to the extent not covered by one of the exceptions stated in Section 1.a.

d. “Purpose” means the release of Confidential/CEII data used by MISO to develop the MISO Transmission Expansion Plan (“MTEP”) and Sector Member’s corresponding use of such data to participate in the MTEP process, as provided under Attachment FF of the Tariff (or any substantially similar successor provision). The “Purpose” does not include any other use of the data by Sector Member.

e. The term “Recipient” means someone who has executed a CEII NDA and is approved to receive CEII.

2. **Non-Use; Protection and Dissemination of Confidential/CEII Data.** Sector Member agrees not to disclose, discuss, use, reproduce, duplicate, distribute, copy, reconstruct or in any way communicate, directly or indirectly, the Confidential/CEII data for purposes other than in connection with the Purpose. Sector Member shall not disclose, discuss, use, reproduce, duplicate, distribute or in any way communicate, directly or indirectly, the Confidential/CEII data to any other party and will use all reasonable efforts to protect the confidentiality of such information. Sector Member will require that Sector Member's employees, officers, directors, agents, contractors, representatives, consultants and advisors who need to have access to such Confidential/CEII data in order to assist Sector Member in connection with the Purpose (1) are aware of the Sector Member's confidentiality obligation hereunder, and (2) agree to be bound by such confidentiality obligations. Sector Member shall notify Disclosing Party immediately of any loss, misuse, or misappropriation of any Confidential/CEII data of which Sector Member becomes aware.

3. **Ownership and Return.** All Confidential/CEII data, including Comingled Material, shall be and remain the property of Disclosing Party (or persons providing information to Disclosing Party), and no right or license is granted to Sector Member with respect to any Confidential/CEII data. No transfer or creation of ownership rights in any intellectual property comprising Confidential/CEII data is intended or shall be inferred by the disclosure of Confidential/CEII data by Disclosing Party, and any and all intellectual property comprising Confidential/CEII data disclosed and any derivations thereof, shall continue to be the exclusive intellectual property of Disclosing Party. Upon the termination by any Party of the Purpose, or sooner if so requested, Sector Member agrees to immediately return all Confidential/CEII data, including Comingles Material, to Disclosing Party or to destroy all Confidential/CEII data, including all copies of the same, however, Sector Member shall not be required to destroy Confidential/CEII data that has become embedded in Sector Member's planning models. Upon request, the fact of any such destruction shall be certified in writing to Disclosing Party by Sector Member. Nothing in this Agreement obligates Disclosing Party to disclose any information to Sector Member or creates any agency or partnership relation between them.

4. **Compliance and Protection of Confidential/CEII Data.** Sector Member represents and warrants that it has practices and procedures adequate to protect against the unauthorized release of Confidential/CEII data received. Sector Member must educate its employees, agents, and assigns in the provisions of this Agreement and provide to Disclosing Party upon request any information necessary to determine compliance with the terms of this Agreement.

5. **Indemnification.** Sector Member agrees to indemnify, hold harmless and defend MISO, its employees, principals (owners, partners, shareholders or holders of an ownership interest, as the case may be), agents, contractors, representatives, consultants and/or advisors against any and all liability, loss, costs, damages, expenses, claims or actions, joint or several, arising out of or by reason of any breach of this Agreement by Sector Member and/or Sector Member's employees, agents, contractors, representatives or consultants, or arising out of or by reason of any act or omission of Sector Member and/or Sector Member's employees, agents, contractors, representatives or consultants in the execution, performance, or failure to adequately perform their obligations under this Agreement. For purposes of this Section, to "indemnify" means to defend and pay all expenses (including reasonable attorneys' fees) and satisfy all judgments

(including costs and reasonable attorneys' fees) which may be incurred or rendered against MISO, its employees, principals (owners, partners, shareholders or holders of an ownership interest, as the case may be), agents, contractors, representatives, consultants and/or advisors.

6. **Compelled Disclosure.** If Sector Member is requested or required by legal or administrative process to disclose any Confidential/CEII data, Sector Member shall promptly notify Disclosing Party of such request or requirement so that Disclosing Party may seek an appropriate protective order or other relief. In any case, Sector Member will (a) disclose only that portion of the Confidential/CEII data that its legal counsel advises is required to be disclosed, (b) use its reasonable efforts to ensure that such Confidential/CEII data is treated confidentially, including seeking an appropriate protective order or agreement, and (c) notify Disclosing Party as soon as reasonably practicable of the items of Confidential/CEII data so disclosed.

7. **Remedies.** The Parties acknowledge that remedies at law may be inadequate to protect Disclosing Party against any actual or threatened breach of this Agreement by Sector Member, and, without prejudice to any other rights and remedies otherwise available to Disclosing Party, agree to not oppose the immediate granting of preliminary and final injunctive relief (without prior notice and without posting any bond) in favor of Disclosing Party to enjoin and restrain any breach or violation, either actual or anticipatory, of this Agreement.

8. **Limitations.** None of the Parties will be under any legal obligation of any kind whatsoever with respect to the Purpose by virtue of this Agreement, except for the matters specifically agreed to herein. No representation or warranty is made by the Disclosing Party as to the accuracy or completeness of any information provided to the Sector Member.

9. **Term and Termination.** Sector Member's obligations under this Agreement shall begin on the Effective Date and shall be perpetual, notwithstanding any expiration, cancellation or termination of this Agreement. Upon termination of the Agreement, Sector Member shall either promptly (1) deliver or cause to be delivered to Disclosing Party or (2) certify to the Disclosing Party the destruction of all Confidential/CEII data (or rendering it electronically unrecoverable), including all copies of the Confidential/CEII data in Sector Member's possession or control including, without limitation, originals and copies of documents, customer lists, prospect lists, price lists, operations manuals, and all other documents reflecting or referencing the Confidential/CEII data, as well as all other materials furnished to or acquired by Sector Member to facilitate the Purpose of the Agreement.

10. **Agency.** This Agreement is binding on Sector Member, its employees, agents, contractors, representatives, consultants, advisors, successors and assigns. In the event of a dispute regarding liability for breach of this Agreement, common law agency principles apply.

11. **Waiver.** No waiver of any of the provisions of this Agreement will be deemed or will constitute a waiver of any other provision, whether or not similar, nor will any waiver constitute a continuing waiver. No waiver will be binding unless executed in writing by an authorized representative of the Party making the waiver. The failure of either Party in any one or more instances to insist upon strict performance of any of the terms and conditions of this Agreement

will not be construed as a waiver or relinquishment, to any extent, of the right to assert or rely upon any such terms or conditions on any future occasion.

12. **Modification.** Except as specified elsewhere in this Agreement, this Agreement may not be amended except in a writing signed by authorized representatives of both Parties.

13. **Governing Law.** Indiana law shall govern the interpretation and implementation of the Agreement and the resolution of any dispute between the Parties regarding the effect of the Agreement without giving effect to principles of conflicts of law, and shall supplement, but not replace, the Uniform Trade Secrets Act as enacted by the State of Indiana. Each Party hereby submits itself for the sole purpose of this Agreement and any controversy arising hereunder to the exclusive jurisdiction of the federal or state courts located in the State of Indiana serving the counties of Hamilton and Marion, and any courts of appeal therefrom, and waives any objection (on the grounds of lack of jurisdiction, or forum not convenient or otherwise) to the exercise of such jurisdiction over it by any such courts.

14. **Severability and Survival.** Should any clause, portion or paragraph of this Agreement be unenforceable or invalid for any reason, such unenforceability or invalidity will not affect the enforceability or validity of the remainder of this Agreement, and any court having jurisdiction is specifically authorized and encouraged by the Parties to hold inviolate all portions of this Agreement that are valid and enforceable without consideration of any invalid or unenforceable portions hereof. The headings of the sections in this Agreement are for the purposes of convenient reference only and are not intended to be part of this Agreement, or to limit or affect the meaning or interpretation of any of the terms hereof.

15. **Assignment and Succession.** This Agreement shall inure to the benefit of and be binding upon the successors and permitted assigns of the Parties hereto. Any successor to or assignee of MISO shall assume its rights and obligations under this Agreement with or without notice to Sector Member. Sector Member may not assign its rights hereunder without the written permission of MISO.

16. **Attorney's Fees.** If Sector Member breaches or defaults in the performance of any of the covenants, agreements, representations, or warranties described in this Agreement, then in addition to any and all of the rights and remedies which MISO may have against Sector Member, Sector Member will also be liable to and pay MISO its court costs and reasonable attorney's fees incurred in enforcing MISO's covenants, agreements, representations and warranties herein.

17. **Sector Member Representatives Bound by Agreement.** The representative executing this Agreement hereby acknowledges and agrees that he/she is duly authorized to execute this Agreement on behalf of Sector Member and that this Agreement shall bind and be enforceable by and against the employees, agents, or consultants of Sector Member. Only those persons who are listed on the attached Appendix A who are not designated as having a “Merchant/Market” function − herein incorporated into this Agreement as updated from time to time by a person identified on Appendix A for Sector Member − shall be authorized to receive Confidential/CEII data directly from MISO. Such persons who receive Confidential/CEII data are

responsible for preventing persons having day-to-day duties and responsibilities for marketing functions from also receiving the Confidential/CEII data. Persons listed on Appendix A shall also be required to execute an individual CEII non-disclosure agreement before being eligible to be a Recipient of CEII data. Sector Member shall timely notify MISO in writing of any modification to Appendix A, which shall be transmitted to help@misoenergy.org (requiring acknowledgment of complete transmission from recipient) or a successor electronic in-box as may be designated by MISO on the customer relations portion of the MISO website.

18. **<u>Notices</u>.** Notices and other communications hereunder shall be in writing and shall be deemed given if delivered personally or by commercial delivery service, or mailed by registered or certified mail (return receipt requested) or sent via email (with acknowledgment of complete transmission from recipient) to the parties at the following addresses (or at such other address for a party as shall be specified by like notice):

if to MISO, to:	720 City Center Drive Carmel, Indiana 46032 Attn: General Counsel Email: legalnotice@misoenergy.org
if to Sector Member, to:	________________________________ ________________________________ ________________________________ Email: ______________________

19. **<u>Applicable Laws and Regulations</u>.** The Parties agree that performance under Agreement shall be pursuant to all Applicable Laws and Regulations, as defined in MISO's Tariff.

20. **<u>Entire Agreement</u>.** The Parties agree that this Agreement, including Appendix A incorporated herein and as modified from time to time, constitute their entire agreement with respect to the subject matter hereof and that it supersedes any prior agreements or understandings between them, whether written or oral.

Sector Member acknowledges that it has read the Agreement, had the opportunity to discuss it with counsel, and is executing it with an understanding of its provisions. This Agreement may be executed in two or more counterparts, each of which will be deemed an original and all of which together will constitute one and the same document.

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[signatures appear on following page]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed, the Effective Date being the last date shown for execution by each of the Parties

Midcontinent Independent System Operator, Inc.	**Sector Member:**
	______________________________
By: ______________________________	By: ______________________________
Print name: ______________________	Print Name: ______________________
Title: ___________________________	Title: ___________________________
Date: ___________________________	Date: ___________________________
Phone: __________________________	Phone: __________________________
Email: ___________________________	Email: ___________________________

Appendix F MISO Default Methodology for TPL P5 Contingency

Transmission Planners may develop their own methodology for selecting NERC TPL 001-5.1 P5 contingencies for evaluation in the NERC TPL Planning Assessments or may point to this default MISO methodology to be used to select NERC TPL-001-5.1 P5 contingencies for inclusion in the NERC TPL Planning Assessments. MISO will use whichever methodology is selected by a Transmission Planner for facilities within the applicable Transmission Owner's footprint.

The MISO default methodology for selecting NERC TPL P5 contingencies is as follows:

- **Step 1:** If the Transmission Planner working in conjunction with the Transmission Owner has verified that a specific transmission facility or terminal has no protection system single-points of failure or has a documented corrective action plan to resolve the single-point of failure, then no P5 contingency is required for that transmission facility. A single-point of failure is a situation where the failure of a single specific component could result in delayed fault clearing or failure to clear a fault. A single component failure that causes only a false trip (overtrip) but does not otherwise interfere with normal clearing of the fault is not considered a single-point-of-failure. *Footnote 13 of the NERC TPL-001-5* defines single-points-of-failure.

- **Step 2:** If the Transmission Planner has verified, based on collaboration with the applicable Transmission Owner and Generation Owners who own generation resources that interconnect to the applicable Transmission Owner's system, that a specific generating unit interconnected to the Transmission Owner's transmission system has no protection system single-points of failure, then no P5 contingency is required for that generation facility. A single-point of failure is a situation where the failure of a single specific component could result in delayed fault clearing or failure to clear a fault. A single component failure that causes only a false trip (overtrip) but does not otherwise interfere with normal clearing of the fault is not considered a single-point-of-failure. *Footnote 13 of the NERC TPL-001-5* defines single-points-of-failure.

- **Step 3:** For those facilities or terminals that have protection system single-points-of-failure or for which the Transmission Planner working in collaboration with the Transmission Owner and/or Generation Owner has not yet determined and verified that protection system single-points-of-failure do not exist, the Transmission Owner and/or Generation Owner will provide to the Transmission Planner the specific facilities that must trip, including consequential load loss, to clear the fault. A NERC TPL P5 steady state contingency will be developed by the Transmission Planner based on the data provide by the applicable asset owner(s). A NERC TPL P5 steady state contingency is used to simulate the post contingent steady state loading and bus voltages that result when remote backup tripping must clear a fault under a protection system failure (including loss of consequential load). The TP and PC will determine in the planning assessment if such a contingency causes steady-state loading or voltage violations, voltage instability or overload cascading.

- **Step 4:** For those facilities or terminals that have protection system single-points-of-failure or for which the Transmission Planner working in collaboration with the Transmission Owner and/or Generation Owner has not yet determined and verified that protection system single-points-of-failure do not exist, the Transmission Owner and/or Generation Owner will provide the following data to the Transmission Planner:

  – Facility or Terminal

  – Time-line of state changes (trips and automatic recloses within one second of the fault) that would occur assuming a failure to trip including i) description of state change (e.g., terminal three-phase trip, terminal three-phase reclose, terminal single-phase trip, terminal single-phase reclose, etc.) and the ii) time after the initial occurrence of the fault that the state change occurred. The time-line should extend to the time when the fault is completely cleared but should not include automatic reclosing beyond one second.

One or more NERC TPL P5 dynamic contingencies will be developed by the Transmission Planner based on the data provided by the applicable asset owner if one or more of the following three conditions apply:

- Any transmission facility directly connected to a transmission bus identified from the annual MISO fast fault screening analysis to potentially be problematic from an angular stability standpoint.

- The transmission facility or generating unit terminates at a transmission bus that interconnects 500 MVA or more of generation capacity, where the 500 MVA applies to the greater of the aggregate generating unit nameplate capability or the aggregate generator step-up (GSU) transformer nameplate capability, expressed in MVA. For the purpose of this default methodology, generating unit nameplate is the aggregate nameplate of all of the rotating machine(s) and/or inverters that supply electrical energy through GSU transformers to the transmission bus in question. For the purpose of this default methodology, a transmission bus represents a specific transmission voltage level at a substation that is represented by either a: i) straight bus, ii) multiple straight buses interconnected by normally closed circuit breakers or other normally closed switchgear, iii) a ring bus, iv) multiple ring buses interconnected by normally closed circuit breakers or other normally closed switchgear, v) a breaker-and-a-half bus or vi) a double-breaker bus. Bus sections of a specific voltage that interconnect only by normally open circuit breakers and/or series reactors would not be considered a common transmission bus.

- The transmission facility is an HVDC transmission facility or an EHV AC transmission facility where an EHV AC facility is any facility that operates at a nominal phase-to-phase RMS voltage greater than 300 kV. For transmission transformers, an EHV AC facility is any facility where the low voltage winding operates at a nominal phase-to-phase RMS voltage greater than 300 kV.

The conditions above define those planning contingencies that produce the more severe system impacts, thus *pursuant to Requirement 4.4 of NERC TPL-001-5.1*, they will represent the P5 dynamic contingencies to be evaluated in the NERC TPL Planning Assessments for a Transmission Owner's system should the applicable Transmission Planner select the MISO default methodology.

A NERC TPL-001-5.1 P5 dynamic contingency simulates the transient impacts of a pro-longed uncleared short-circuit fault on the transmission system followed by the loss of multiple transmission facilities (and associated consequential load loss) that occur to eventually clear the fault. A dynamic contingency includes the impact of high-speed automatic reclosing (less than one second), but not time delayed automatic reclosing (greater than or equal to one second). Such a contingency is simulated by the PC and TP in the planning assessment to see if angular instability, system separation or cascading due to overloads and/or power swings will occur.

It is important to note that when a TPL-001-5.1 P5 dynamic contingency is required, a separate contingency is required at each terminal where a fault at that terminal and a subsequent protection system failure could result in a failure to trip that terminal and thus result in delayed clearing of the fault. For a given P5 dynamic contingency, a fault at a specific terminal will assume a failure to trip occurs at the faulted terminal only, unless a single-point-of-failure results in simultaneous trip failures at multiple terminals (e.g., transformer faults, bus faults, etc.), in which case the assumption should be failure to trip at multiple terminals. It will not be necessary to develop a P5 dynamic contingency for a short-circuit fault at a specific terminal where the trip failure is at a remote terminal only since this situation does not represent more severe system impacts than a trip failure at the terminal where the fault is located. However, to the extent the remote terminal protection is also subject to a single-point-of-failure, a P5 dynamic contingency would be developed at the remote terminal simulating a fault at the remote terminal and the failure of the remote terminal to trip.

Appendix G Transmission System Voltage Performance Criteria for Geomagnetic Disturbance (GMD) Events

The NERC TPL-007 Transmission Planning standard requires the Planning Coordinator to establish criteria for acceptable system steady state voltage performance during GMD events (Requirement R3). As the Planning Coordinator, the standard MISO practice will be to monitor against Transmission Planners' Emergency voltage thresholds listed in their Local Planning Criteria (LPC). If an LPC is absent, MISO's default planning criterion Emergency voltage thresholds will be used, *see Table G-1 below*.

Table G-1: MISO's Default Planning Criteria for GMD Events

Steady State Voltage (Pursuant to TPL-007 Requirement R3)	Threshold (p.u.)
Emergency Low Voltage	0.90
Emergency High Voltage	1.10
Post GMD Event Maximum Voltage Deviation	0.05

Emergency voltage thresholds will be applied post-GMD event, but prior to the loss of any BES elements due to increased harmonic current flow because of the GMD event. Once any BES elements are lost due to harmonics, the MISO BES transmission system will be monitored to ensure that there is no voltage collapse, cascading or uncontrolled islanding in any part of the transmission system. Nuclear Plants will continue to follow voltage criteria per existing Nuclear Plant Interface Requirements (NPIRs). The NERC defined TPL-007 Transmission Planning standard is applicable to the facilities with nominal voltage level greater than 200 kV. However, MISO will monitor the facilities with nominal voltage level greater than 100 kV to ensure better visibility into the system for a post-GMD event.

Appendix H Reserved

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Appendix I Immediate Need Reliability Project Procedure

I.1 Immediate Need Reliability Project Procedure

The following procedures have been developed within the MISO Transmission Expansion Plan (MTEP) process as *outlined in Section VIII.A.3.1 of Attachment FF of the Tariff* and provide transparency in the progression of projects that may qualify as Immediate Need Reliability Projects (INRP).

The Competitive Developer Selection Process does not apply to an Eligible Project[35] that meets the Immediate Need Reliability Project criteria and MISO will designate the applicable Transmission Owner in Appendix A of MTEP in accordance with *Section VIII.A.3 of Attachment FF in the MISO Tariff*.

I.2 Identify Candidate INRP

On an annual basis Transmission Owners submit bottom-up projects into the MTEP Project Database *according to Section 2.4.5 of this BPM*. MISO will identify all bottom-up projects that may qualify as a Baseline Reliability Project *pursuant to Section II.A.1 of the Tariff*, for which the voltage is greater than or equal to 230 kV, the estimated cost is greater than or equal to $5M, and the Baseline Reliability Project has an in-service date that is within 36 months from the first day of the month when the Board of Directors is expected to approve the MISO Transmission Expansion Plan. MISO will identify the candidate projects that meet the criteria described above at the first Subregional Planning Meeting *outlined in Table 4.1.1–1: SPM Meeting Schedule of this BPM*.

I.3 Confirm Candidate INRP

Once MISO completes the project justification portion of its initial Baseline Reliability Study for the candidate INRP, MISO will confirm the candidate INRP at the second Subregional Planning Meeting *outlined in Table 4.1.1–1: SPM Meeting Schedule of this BPM*.

I.4 Determine Immediate Need Reliability Projects

[35] The Tariff defines "Eligible Projects" as "any Market Efficiency Projects ("MEP") and Multi-Value Projects ("MVP") approved by the Transmission Provider's Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider's Competitive Developer Selection Process. *Tariff Module A*—Definitions.

Once MISO completes its economic planning analysis to determine if any Baseline Reliability Projects in the current MTEP cycle qualify as a Market Efficiency Project as described in Section 7.4 (Market Efficiency Projects) of this BPM and in accordance with Section II.B of the Tariff, MISO will determine whether any candidate Immediate Need Reliability Projects satisfy all of the criterion *in Section VIII.A.3 of Attachment FF of the Tariff* at the third Subregional Planning Meeting *outlined in Table 4.1.1–1: SPM Meeting Schedule of this BPM*.

MISO will include the required information *outlined in Section VIII.A.3.1 of Attachment FF of the MISO Tariff* in the MISO Transmission Expansion Plan for which the Immediate Need Reliability Projects is being recommended for inclusion in Appendix A.

I.5 Publish Immediate Need Reliability Projects

MISO will update its list of Eligible Projects on its website within thirty (30) Calendar Days after the MISO Board of Directors approves a MISO Transmission Expansion Plan that includes an Immediate Need Reliability Project. The list will be posted on MISO's MTEP page at MTEP Page.

In addition, within thirty (30) Calendar Days after the MISO Board of Directors approves a MISO Transmission Expansion Plan that includes an Immediate Need Reliability Project, MISO will include in the MTEP report published on MISO's website the required information *outlined in Section VIII.A.3.1 of Attachment FF of the Tariff* in the MISO Transmission Expansion Plan for each the Immediate Need Reliability Project that has been approved for inclusion in Appendix A.

I.6 Solicitation for and Publication of Stakeholder Comments

MISO will solicit stakeholder comments once it has added an Immediate Need Reliability Project to the Eligible Projects table on its website. MISO will solicit stakeholder comment using its Planning Subcommittee and Planning Advisory Committee email exploder lists. Stakeholders will have thirty (30) Calendar Days to submit comments.

MISO will publish the stakeholder comments received together with MISO responses within sixty (60) days after adding an Immediate Need Reliability Project to the Eligible Projects table on its website. The stakeholder comments will be posted on the Immediate Need Reliability Project website, which can be accessed on the Eligible Projects website.

I.7 Dispute Resolution

Please *see Section VIII.A.3.2 in Attachment FF of the Tariff* for dispute resolution with respect to an Immediate Need Reliability Project.

Appendix J Implementation Rules for LODF Calculation

J.1 Line Outage Distribution Factor (LODF)

The LODF method determines the impact of a new facility planned as part of an expansion project on other, existing components for a defined region. LODF equals the change in flow on a facility due to the outage of a new project facility and is absolute value of facility flow change divided by flow on new project facility prior to outage. Where a project consists of multiple facilities, each new project facility is outaged for its effect on the MISO system facilities.

As an example, consider a new project facility with a post-project powerflow of 100 MW. An existing MISO facility has pre-project flow of 200 MW and a post-project flow of 180 MW. The existing circuit flow change is 20 MW between the cases. The LODF for the existing circuit is 20 percent, as calculated:

Equation J.1-1: LODF Calculation

$$\boxed{\frac{ABS(200\,MW - 180\,MW)}{100\,MW} = 20\%}$$

MISO calculates Line Outage Distribution Factor of the proposed expansion project for each existing component within the MISO footprint rated at 100 kV and above. In the event that a component's LODF is less than one (1%) percent e.g., the monitored component's power flow changes by less than one percent with the addition of the proposed expansion project, the component is excluded from further cost allocation calculations.

The LODF is then applied to each affected existing component according to the mileage rating of the component. A cost allocation value, called the "Sum of Absolute Value of LODF-Mile" (LODF-Mile), is calculated by multiplying the LODF times the mileage, for each component affected by a given expansion project. Transmission Owner(s) are expected to provide line length (in miles) for all transmission system components. Where the component mileage is not available, MISO planning staff estimates mileage using model impedance values and typical impedance per mile rates for similar components. Transformers are given a designated mileage rating of one mile.

J.2 Calculating LODF for Complex Projects

When there is a complex system reconfiguration, a project boundary flow is used to calculate LODFs for the project facilities using *Equation J.2-1 below*. The project boundary flow is the equivalent to pre-outage flow for single new project facility. The project boundary flow is calculated by drawing a boundary around the project area and calculating net flow for pre-project and post-project models. The difference in project boundary flows is the divisor used for LODF calculations. The before and after project case flows difference are calculated for all MISO facilities.

As an example, consider a project with difference in project boundary flows of 100 MW. A MISO facility has pre-project flow of 200 MW and a post-project flow of 180 MW. The existing circuit flow change is 20 MW between the cases. The LODF for the existing circuit is twenty (20%) percent, as calculated:

Equation J.2-1: LODF Calculation

$$\boxed{\frac{ABS(200\ MW - 180\ MW)}{100\ MW} = 20\%}$$

J.3 General LODF Methodology and Thresholds

- Use "Sum of Absolute value of LODF-Mile" method to develop subregional cost allocation percent. This metric is calculated by multiplying the LODF times the mileage, for each component affected by a given expansion project. All MISO Transmission Facilities are monitored.
- LODF cutoff rate: one (1%) percent, if a monitored branch does not respond by one (1%) percent of the project line flow, its impact is ignored
- Mileage: Line length is provided in the applicable powerflow model or is reported by Transmission Owner for monitored branches. If not reported, it will be calculated through model impedance and typical values for impedance/mile. Transformers are set to be one mile.
- Only facilities with both terminal 100 kV and above are considered for allocation in the computation.
- The Transmission Pricing Zone (TPZ) of a monitored facility will be approximated by the model control area in the applicable powerflow model, subject to review by the impacted Transmission/Facility Owners(s)
- Tie-lines: Percent ownership as reported by Transmission Owner(s). Otherwise the default owner is control area of non-metered Bus terminal in model.
- LODF for Projects consisting of multiple branch additions or upgrades will be determined by breaking the project up into its separate branches, and determining the LODF allocation for the cost of each branch. This will avoid masking of proximity effects of the new project (which is the principle of the LODF) where individual

branches of a project may have counter-impacts that net to a small impact on nearby facilities. When the LODF is calculated for one of the branches of a multiple branch project, each of the other branches of the project is included in the model, however, the LODF contribution on other branches of the new project are not counted.

- Where a monitored line is a Remote Line not in the owner's pricing zone the LODF impacts on the Remote Line will be added to the LODF impacts of all other lines of the pricing zone that the Remote Line is in, see Section J.5 below.

J.4 Models and Applicable Topology

- The applicable MTEP planning horizon model is used for all project LODF calculations. For example, if a five-year-out model is being used for MTEP, and a project is first identified as a required Generator Interconnection Project from a pricing zone which used LODF cost allocation in that MTEP process, the five-year-out model will be used even though the project may have a three-year-out service date. This avoids the need to develop many different models for LODF determination.
- Both Appendix A and Target Appendix A Projects will be included in the MTEP planning horizon model, per the requirements of the MTEP model building process.
- Existing HVDC lines will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility.
- Existing Phase Angle Regulators will be modeled as fixed flow with flow controlled to the level set for normal system conditions with the new facility.

J.5 Project Specific Methodology

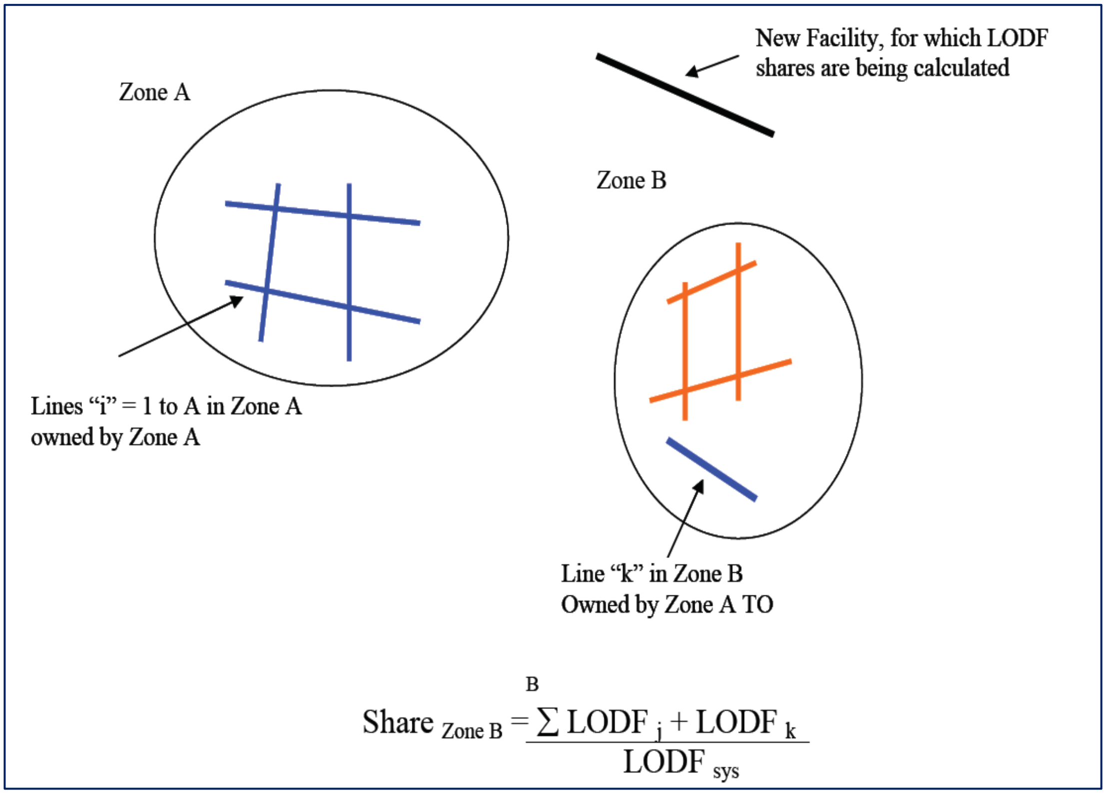
- A reconductored line can be simulated as the original line with a parallel pseudo line. LODF will be computed by taking out the parallel line. Alternatively, comparison of line flows between the base system and the change system will be used to develop LODF values.
- Rebuilds involving conversion (removal) of a low voltage facility to a high voltage facility (addition) will compare line flows between the base system and the change system to develop LODF values.
- A series inductor or capacitor will use the same approach as for reconductored lines.
- Looped lines will be treated as any other line. A looped (non-radial) line is a networked extension of an existing line to a new substation.
- Terminal upgrades (including bus sections, switches, circuit breakers, protection devices): If equipment is stand alone, the LODF calculation is not required because there is no impedance change.

- For shunt-connected devices (capacitors, SVCs, reactors), the LODF calculation is not required because there is no impedance change.

J.6 Treatment of Monitored Lines Outside of the Owner's Zone

This is the "Location" or "Load Based" approach. This will include in the Zone B share the flow impacts of all lines in a Zone B, regardless of line ownership.

Figure J.5-1: Example Showing Location Matters Not Ownership



J.7 Cost Allocation Considerations

- For a project or facility that does not alter system impedance (e.g., circuit breaker or terminal equipment), all costs will be one-hundred (100%) percent local.
- For projects consisting of facilities at multiple voltages, each facility will be evaluated for postage-stamp eligibility based on its voltage class.
- Costs of 345 kV or higher voltage substation facilities that are installed as a part of a new transformer installation for transformers with high side voltages of 345 kV or higher and low side voltages of 344 kV or lower, and that are needed only to support a new transformer installation shall be lumped with the cost of the transformer and given the same cost allocation treatment as for the transformer. As an example, a new 345 kV Bus and circuit breakers needed to install a new 345/138 kV transformer would not be postage-stamped but would be allocated according to the LODF of the transformer serving the 138 kV system. Costs of related 345 kV equipment such as a line extension to the new 345 kV class substation will be treated on a case-by-case basis depending on the intended future plans for additional networked lines to be installed at the substation. Costs of 345 kV Bus and circuit breakers related to new

line installations at the same time as the transformer installation will be treated as 345 kV facilities and given the postage-stamped treatment.

- Projects or facilities driven solely by contingency loss of, or design violations of, facilities of 69 kV and below will not be cost shared.
- Cost of shunt-connected devices (capacitors, SVCs, reactors) required for Load-serving steady-state voltage control or voltage quality will NOT be shared, unless such devices are also needed to remedy stability or to increase transfer capability for reliability purposes (import capability or generator deliverability). Stability and reliability-transfer-related shunts will have costs shared ten (10%) percent Postage-Stamp with the remaining ninety (90%) percent assigned locally for shunts connected to 345 kV and above (LODF = 1 for local branches, 0 for others), and one-hundred (100%) percent assigned locally for below 345 kV.
- Cost of terminal upgrades, including Bus sections, switches, circuit breakers and other protection devices, that are an integral part and necessary to integrate a project involving a line or transformer addition or enhancement are lumped with and allocated as per the allocation percentages for the related branch facilities.
- The costs of upgrades to existing circuit breakers or other interrupting devices that are needed due to increased interrupting duty or continuous loading capability requirements will be allocated one-hundred (100%) percent local.

Appendix K Default MISO Planning Criteria

The NERC TPL-001 planning standards require the Planning Coordinator and Transmission Planning to establish certain planning criteria (TPL-001-5 Requirement R5 and R6). Transmission Planners are responsible for developing planning criteria and methodologies for their own footprints in accordance with the TPL standards. As the Planning Coordinator, the standard MISO practice will be to use the planning criteria developed by each Transmission Planner for issues within the footprint of that Transmission Planner, or if issues extend across multiple Transmission Planner footprints, the most conservative of the planning criteria developed by each applicable Transmission Planner. In cases where the Transmission Planner does not develop specific planning criteria, MISO, as the Planning Coordinator, will use the default planning criteria contained within this attachment. Furthermore, Transmission Owner(s) may point to the MISO default planning criteria as their own planning criteria in lieu of developing their own such criteria and methodologies if they so choose.

Table K-1: Default Planning Criteria

Steady State Voltage (Pursuant to TPL-001-5 Requirement R5):	
Normal Low Voltage Limit (p.u.)	0.95
Normal High Voltage Limit (p.u.)	1.05
Emergency Low Voltage Limit (p.u.)	0.9
Emergency High Voltage Limit (p.u.)	1.1
Post Contingency Maximum Voltage Deviation (p.u.)	0.2
Transient Voltage: Generator Low Voltage Ride-Through Capability* (Pursuant to TPL-001-5 Requirement R5)	
0.00 to 0.15 seconds (p.u.)	0
0.15 to 0.30 seconds (p.u.)	0.45
0.30 to 2.00 seconds (p.u.)	0.65
2.00 to 3.00 seconds (p.u.)	0.75
Beyond 3.00 seconds (p.u.)	0.9
Transient Voltage: Generator High Voltage Ride-Through Capability* (Pursuant to TPL-001-5 Requirement R5)	
0.00 to 0.20 seconds (p.u.)	1.2
0.20 to 0.50 seconds (p.u.)	1.175
0.50 to 1.00 seconds (p.u.)	1.15
Beyond 1.00 seconds (p.u.)	1.1
Transient Voltage: Load Low Voltage Recovery Limits (Pursuant to TPL-001-5 Requirement R5)	
0.00 to 20.00 seconds after fault clearing (p.u.)	0.7
Beyond 20.00 seconds after fault clearing (p.u.)	0.9
Stability Criteria (Pursuant to TPL-001-5 Requirement R6)	

Angular Transient Stability Minimum Damping Ratio (ζ)	0.03
Angular Transient Stability Critical Clearing Time Margin (cycles)	1
Voltage Stability Maximum Transfer Limit (% of transfer at nose of PV curve)	90
Cascading Outage Definition (Pursuant to TPL-001-5 Requirement R6):	
Number of inadvertent elements tripping: If Total Load Loss ≤ 1000 MW*	3 or more
Number of inadvertent elements tripping: If Total Load Loss > 1000 MW*	1 or more

**Note 1: Based on Attachment 2 of NERC PRC-024.*

***Note 2: The number of BES line and/or transformer circuits that were tripped due to circuit overloads or power swings subsequent to the elements tripped by the protection system to clear the contingency fault.*

****Note 3: Total Load loss does not include consequential Load loss from elements tripping to clear the fault.*

Appendix L SOL (IROL) Methodology for the Planning Horizon

L.1 Definitions

MISO establishes SOLs and IROLs for the Planning Horizons. The provided SOLs (including the subset of SOLs that are IROLs) shall include the identification of the subset of multiple contingencies (if any) from Reliability Standard TPL-001 which result in stability limits. The SOL/IROL Limits attained from Steady State, Voltage Stability, and Transient Stability analyses for the MTEP planning horizon is posted to two secure locations: The MISO ShareFile site.

Instructions for access for the MTEP ShareFile site are found at: Client Relations

The methodology for developing SOLs and IROLs for the Planning Horizon is described in this document.

L.1.1 Applicability of SOLs for the Planning Horizon

This methodology is applicable for developing SOLs used in the planning horizon.

L.1.2 Relationship of SOLs and Facility Ratings

SOLs in the planning horizon are described as the most limiting facility rating considering its design thermal or voltage rating together with the system conditions at which the limit is reached or exceeded when applying the TPL standards under base system conditions and simulating Transfer Capability Analysis in accordance with the MISO Transfer Capability Methodology in Appendix N of this BPM. The SOL condition shall not produce any facility Loading or voltage condition that exceeds the most limiting element that determines the Facility Rating.

L.1.3 Relationship of SOLs and IROLs

By definition, IROLs are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System. Therefore, IROLs in the planning horizon are described as the system condition(s) (system or area demand level and facility contingency conditions) *consistent with the NERC TPL standards*, and simulating Transfer Capability Analysis *in accordance with the MISO Transfer Capability Methodology in Appendix N of this BPM*, for which instability, uncontrolled separation, or Cascading Outages are projected to occur.

L.2 Determination of SOL Conditions in the Planning Horizon

Near and longer term planning addresses identification of needs and solutions in the time frame of one to ten years, with particular focus on the first five (5) years. Screening reliability analyses are performed in the six to ten year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards.

Baseline reliability analysis provides an independent assessment of the reliability of the currently planned MISO Transmission System for the near-term planning horizon (e.g., within the next five years). This is accomplished through a series of evaluations of the near-term system with Planned (committed) and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through a combination of steady-state power flow, dynamic and First Contingency Incremental Transfer Capability (FCITC) Transfer Capability analyses of the transmission system performed by MISO staff and reviewed in an open stakeholder process.

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and regional study group input. The list of contingencies will include events described under NERC TPL-001 or any applicable local or RRO planning criteria or guidelines. Below is a list of typical contingency categories tested. The extent that SOLs affect BES performance is determined using the following contingency criteria:

L.2.1 Pre Contingency State

The transmission system is modeled under NERC category P0 conditions (e.g., system intact) using both steady-state and dynamic stability analysis. Potential planning criteria violations (thermal overload and low or high voltage conditions) are identified using Transmission Owner's design criteria limits. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to the system topology such as applicable planned facility outages in the planning horizon.

L.2.2 Post Contingency State

The transmission system is modeled under NERC category P1 through P7 conditions (e.g., loss of single or multiple Bulk Electric System elements, respectively) using both steady-state and dynamic stability analyses and under NERC category P1 using Transfer Capability analyses.

Planning criteria violations (thermal overload and low or high voltage conditions) are identified using Transmission Owner's design criteria limits. Following the single Contingencies—(R2.2.1) Single line to ground or three-phase fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device or (R2.2.2) the loss of any generator, line, transformer, or shunt device without a Fault or a (R2.2.3) Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system—the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. For Transfer Capability analysis, dynamic and voltage stability studies shall be conducted at the established FCITC thermal linear limit for NERC category P1 contingent conditions and to the extent either dynamic or voltage instability is identified at the FCITC thermal linear limit, a lower stable FCITC will be calculated. An SOL shall be established on the constrained element based on its pre-contingent flow at the stable FCITC limit.

L.2.3 Single Contingency System Response

For the near-term planning horizon, any potential criteria violations under NERC category P1 conditions are thoroughly analyzed. This analysis identifies possible corrective measures to prevent or mitigate potential violations, including operating procedures, construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled interruption to local Network Customers within the Faulted Facility affected area. The planning process also determines that appropriate preventative or mitigation measures can be put in place before the need is expected to occur in the planning horizon.

L.2.4, L.2.5, L.2.6, L.2.6.1 Multiple Contingency System Response

For the near-term planning horizon, modeled criteria violations under NERC category P2 through P7 conditions are evaluated for their potential to result in Cascading Outages or uncontrolled separation. This analysis identifies possible corrective measures to prevent or mitigate Cascading Outages or uncontrolled separation, including construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled load interruption or curtailment of firm transfers. The planning process also determines appropriate preventative or mitigation measures can be put in place before the end of the planning horizon.

L.3 Baseline Models

The MISO Baseline Reliability study models will typically include power-flow models reflective of five-year out and ten-year out system conditions. Other variations of these may also be used as appropriate based on the stakeholder input for a given planning cycle. The determination of SOLs and IROLs in the Planning Horizon establishes limits that are based on a representation of the actual transmission system capability. Reliability margins are not applied in the SOL/IROL analysis. The MISO SOL methodology consists of each of the following elements:

L.3.1 Topology

The system topology in the Baseline Reliability Plan models will reflect the expected system condition for the planning horizon. This will include documented future transmission projects within the MISO Transmission System. The Baseline Reliability Plan models shall include at least the entire MISO's Planning Coordinator area as well as any critical modeling details from other Planning Coordinator areas deemed necessary to impact the Facility or Facilities under study. The following general criteria will be used to model future transmission projects:

- Planned projects with Expected In-Service Date before the MTEP study horizon year (before July 15th for summer peak cases);
- Projects with Regulatory Approvals;
- Projects with system needs documented by a MISO study (i.e., a previous MTEP study, a Generator Interconnection study, a Transmission Service study, or a Coordinated Seasonal Assessment);
- Planned projects based on Conditionally Confirmed TSR upgrades;
- Upgrades related to Generator Interconnection requests with signed Generation Interconnection Agreements (GIAs);
- Projects which are not subject to cost sharing.

Future transmission upgrades are removed from the model if they have Withdrawn Planning Status, or if they do not meet the inclusion criteria above. The non-MISO system representation will be based on the latest external system for the planning horizon.

L.3.2 Contingencies

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and regional study group input. The list of contingencies will include events described under NERC TPL-001, or any applicable local or Regional Entity planning criteria or guidelines. Below is a list of typical contingency categories tested.

- NERC category P0: is system intact or no contingency event.
- All Category P1: faulted events for systems under MISO operational control. Generally, greater than 100 kV, but includes some 69 kV. Category P1 includes single generator, transmission circuit and transformer outages. It also includes single pole block of DC lines.
- NERC category P2 through P7 faulted events: The more severe events will be

studied per the standards. All events will be documented and studied over study cycle. Transmission Owner(s) and MISO staff will document NERC category P2 through P7 coverage.

L.3.3 Granularity of Models

The MTEP base models include all networked transmission system elements rated 100 kV and above. Additionally, the base model includes certain 69 kV elements that have been identified by Member Transmission Owner(s) as potentially significant for local system reliability studies.

L.3.4 Remedial Action Plans

The MISO base model for evaluating SOLs includes analysis of known Special Protection Systems and Remedial Action Plans.

L.3.5 Generation, Load, and Interchange

All existing generators and future generators with a filed Interconnection Agreement will be modeled. Any additional generation needed to serve future Load growth will be modeled based on input from future generation modeling processes described *in Section 4.3.3.2 of this BPM*. New information on generators in the external system through coordinated data exchange with other external entities will also be modeled. Retirement of existing generators will also be updated based on the information available through the System Support Resource study process, *see Section 6.2 of this BPM*. The Load Forecast information is based on the stakeholder input in the model building process. This information is reviewed and compared against Load flow data from NERC series models, Load Forecast information as filed with FERC and State regulatory agencies. Interchange and transaction data are also updated via the model building process which will include any new transactions or changes from the Transmission Service Planning process.

L.3.6 Criteria for determining when violating an SOL qualifies as an IROL

In the annual MTEP planning study, for multiple contingencies, the following criterion applies in determination of SOLs which qualify as IROLs:

- **MTEP Steady State Analysis**: After performing the steady state analysis to determine each SOL, additional analysis will be performed to identify thermal overloads in excess of SOL demonstrated to result in cascading loss of Load in excess of 1000 MW. Monitoring of MISO facilities shall be performed at the following facility rating thresholds (*consistent with PRC-023*):

- If the Facility Rating is based on a Loading duration of up to and including four hours, the circuit loading threshold is one-hundred fifteen (115%) percent of the Facility Rating.
- If the Facility Rating is based on a Loading duration greater than four and up to and including eight hours, the circuit Loading threshold is one-hundred twenty (120%) percent of the Facility Rating.
- If the Facility Rating is based on a Loading duration of greater than eight hours, the circuit loading threshold is one-hundred thirty (130%) percent of the Facility Rating.

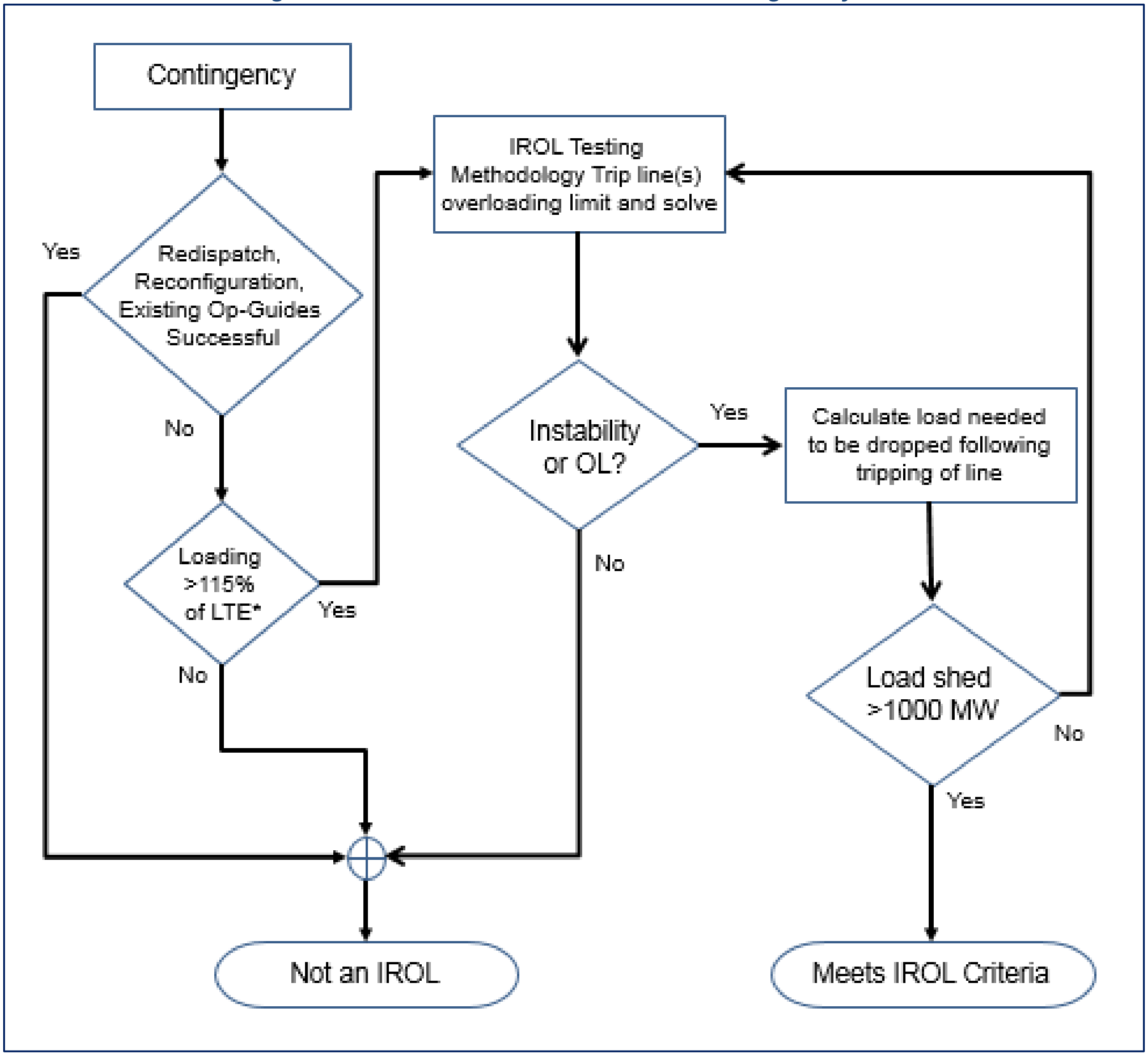
To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the above thresholds, MISO will use TOs rating thresholds.

By NERC definition, an IROL is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System. To the extent that an applicable contingency causes post contingency flow greater than the aforementioned facility emergency ratings above, the cascading test, *see Figure L.3.6-1 below,* will be used to determine the amount of load lost on the system for the event. If the amount of firm load loss is greater than 1000 MW it will be classified as an IROL.

The 1000 MW load loss limit was selected to define the IROL threshold since it is consistent with what operations uses, and more generally, while it may cause significant regional impact, from the standpoint of interconnection-wide impacts it seems a reasonable limit.

The cascading test methodology is shown below and is performed using the Loading duration threshold to identify a cascading condition for the determination of an IROL.

Figure L.3.6-1: General Process for Cascading Analysis



***Use** one-hundred fifteen (115%) percent of LTE unless Transmission Provider has supplied another Loading level to use

- **MTEP Transient Stability Analysis**: After performing the transient stability analysis to determine each SOL, additional analysis will be performed to determine instabilities identified for multiple contingencies resulting in cascading loss of Load in excess of 1000 MW.

- **Near Term Transfer Capability Analysis**: The following studies shall be conducted to determine IROLs based on transfer studies. Transfers to be studied shall be established pursuant to MISO's Transfer Capability Methodology documented *in Appendix N of this BPM*. The most limiting transfer IROL limit with cascading loss of Load impact in excess of 1000 MW shall be established for each studied transfer path where this limit is lower than the established FCITC SOL thermal linear limit. These limits shall be based on the following studies and designated as IROL, and both the monitored and contingent elements associated with each limit shall be designated as an IROL limited facilities.
  - **Thermal Study**: Steady State testing using multiple contingencies performed while monitoring MISO facilities at the following facility rating thresholds (*consistent with PRC-023*):
    - If the Facility Rating is based on a Loading duration of up to and including four hours, the circuit loading threshold is one-hundred fifteen (115%) percent of the Facility Rating.
    - If the Facility Rating is based on a Loading duration greater than four and up to and including eight hours, the circuit Loading threshold is one-hundred twenty (120%) percent of the Facility Rating.
    - If the Facility Rating is based on a Loading duration of greater than eight hours, the circuit loading threshold is one-hundred thirty (130%) percent of the Facility Rating.

To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the above thresholds, MISO will use TOs rating thresholds.

Potential IROL limit shall be established if the above thresholds are exceeded at transfer levels below the SOL FCITC transfer limit and cascading loss of Load is determined to be in excess of 1000 MW. Both the monitored and contingency elements associated with the limit shall be designated as potential IROL limited facilities.

- **Steady State Voltage Stability**: Voltage stability analysis shall also be simulated for each of the thermal transfers to assess IROLs from a reactive capability standpoint. To the extent voltage instability limit (with loss of Load in excess of 1000 MW) is identified to be lower than the thermal transfer IROL limit, the lower IROL shall be established on an interface associated with the transfer path. Both the monitored and contingency elements associated with the instability shall be designated as IROL limited facilities.

- **Transient Stability**: Transient stability analysis shall be conducted on the transfer study case. The transfer at the lower of the two IROL limits established either through thermal or voltage stability study shall be incorporated in this study case. To the extent instability (with loss of Load in excess of 1000 MW) is identified for simulated applicable disturbances, a lower IROL limit at the transfer point where no voltage, thermal or transient instabilities are identified shall be established. Both the monitored and contingency elements associated with the instability shall be designated as IROL limited facilities.

To the extent that any IROLs are the result of system topology changes introduced through future planned upgrades as determined by Transmission Owner(s), MISO shall also document an applicable future date against these associated IROLs. These dates would align with the in-service dates for the associated future projects.

MISO, as a Planning Coordinator, does not develop IROL T_v; however, MISO applies a default value of thirty (30) minutes for all IROLs identified in the Planning Horizon based on the maximum value specified in the NERC definition of IROL T_v. MISO's SOL and IROL determination in the Planning Horizon is intended to provide an indication of potential reliability impacts in future system conditions that may require monitoring and further evaluation for operational concerns. The assessment does not include a detailed analysis for developing operating actions needed to mitigate the risks of SOL and IROL exceedances and therefore, MISO does not develop T_v for the IROLs identified in the Planning Horizon.

L.4 Issuance of Documentation

This SOL Methodology, and any change to it, will be issued to the following entities prior to the effectiveness of the change.

L.4.1 Adjacent Planning Coordinator

Each adjacent Planning Coordinator and each Planning Coordinator that indicated it has a reliability-related need for the SOL Methodology.

L.4.2 Reliability Coordinator and Transmission Operator

Each Reliability Coordinator (MISO) and Transmission Operator that operates any portion of the MISO's Planning Coordinator Area.

L.4.3 Transmission Planner

Each Transmission Planner that plans a portion of the MISO Planning Coordinator Area.

L.5 Documented Response Time

If a recipient of this SOL Methodology provides documented technical comments on the methodology, the MISO will provide a documented response to that recipient within forty-five (45) Calendar Days of receipt of those comments. The response will indicate whether a change will be made to the SOL Methodology and, if no change will be made, the reasoning behind the decision.

L.6 Data Retention Period

The MISO shall keep all superseded portions of this SOL Methodology for twelve (12) Months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three (3) years.

Appendix M Planning Horizon PRC-023 Applicable Facility Identification Procedure

M.1 Requirement Six (R6)

Pursuant to requirement R6, MISO shall conduct an annual assessment once every calendar year, with no more than fifteen (15) months between assessments. MISO shall utilize the MISO Transmission Expansion Plan (MTEP) study and MISO Master Flowgate list as part of the annual assessment. PRC-023 Attachment B Criteria shall determine the circuits in MISO area, for which Transmission Owner(s), Generation Owners and Distribution Providers must adhere to PRC-023, Requirements R1 through R5 in order to prevent its phase protective relay settings from limiting transmission system Loadability, while maintaining reliable protection of the BES for all fault conditions. Circuits evaluated are transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, or circuits operated below 100 kV that have been classified as part of the BES.

M.1.1 PRC-023 Attachment B Criteria

MISO shall identify these circuits once a year pursuant to the criteria documented below that is consistent with each sub criterion *within Attachment B of PRC-023*. If inputs under Attachment B sub requirements are developed more frequently than once a year or revised within a year MISO shall review and may update the circuit list if needed.

- **M.1.1.1: Criterion B1** - Upon completion of MISO's reliability assessment, MISO shall annually incorporate the most current permanent flowgates within MISO Planning Coordinator footprint that are part of the MISO Master Flowgate list in establishing its initial facility list. In subsequent assessment years, MISO will update the facility list determined pursuant to this criterion based on additions or deletions to the permanent flowgate list annually.
- **M.1.1.2**: **Criterion B2** - MISO will incorporate circuits which are monitored facilities of an IROL into its facility list following completion of its annual reliability assessment. The methodology used in determining these IROLs established pursuant to FAC-010 and FAC-014 is documented in Appendix L of this BPM.
- **M.1.1.3**: **Criterion B3** - Consistent with NUC-001-2, MISO maintains mutually agreed upon Nuclear Plant Operating Agreements which include Nuclear Plant Interface Requirements (NPIRs) with Generator Owners and applicable Transmission Planners within its footprint. MISO shall incorporate

the circuits that form a path to supply off-site power to nuclear plants as established within applicable NPIRs in its facility list annually.

- **M.1.1.4**: **Criterion B4** - Circuits included on the facility list shall be identified through the following sequence of power flow analyses performed by the planning coordinator for the one-to-five year planning horizon. In order to monitor thermal loading, MISO shall utilize facility rating thresholds consistent with the following sub requirements:
  - Simulate double contingency combinations, without manual system adjustments in between the two contingent events.
    - The contingency pairing for NERC TPL category P6 events is intended to simulate contingencies that produce the most severe impact. Due to the large footprint of MISO, groups are developed to represent facilities in closer proximity and are representative of the MISO Local Resource Zones. All BES contingency combinations within a group are simulated. Contingencies in adjacent groups are paired by operating voltage and generation capacity thresholds.
  - For facilities operated between 100 kV and 200 kV (and facilities less than 100 kV that have been classified as part of the BES), evaluate the post-contingency loading based upon the Facility Rating assigned to that circuit, in consultation with the Facility Owner and included in the MISO Transmission Expansion Plan base models.
  - Where more than one applicable rating exists, the rating based on the loading duration nearest four hours will be used.
  - Rating based on loading duration assumed:
    - If the Facility Rating is based on a load duration of up to and including four hours, the circuit load threshold is one-hundred fifteen (115%) percent of the Facility Rating.
    - If the Facility Rating is based on a load duration greater than four and up to and including eight hours, the circuit load threshold is one-hundred twenty (120%) percent of the Facility Rating.
    - If the Facility Rating is based on a load duration of greater than eight hours, the circuit load threshold is one-hundred thirty (130%) percent of the Facility Rating.
    - To the extent facility rating thresholds established by MISO Transmission Owner(s) (for purposes of IROL identification) are lower than the outlined thresholds, MISO will use the lower rating thresholds.

- MISO will exclude radially operated circuits and generation Step Up transformers, which are used exclusively for exporting energy from a BES generation unit or plant.

- **M.1.1.5**: **Criterion B5** - MISO conducts technical studies annually as part of its reliability assessment to determine additional facilities other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- **M.1.1.6**: **Criterion B6** - The MISO shall supplement the list of circuits developed pursuant to sub requirements B1 through B5 above with additional facilities identified by the MISO Transmission Owner(s). MISO will solicit its Transmission Owner(s) for this list once a year before establishing its annual facility list.

M.1.2 Requirement R6.1

MISO shall annually (once every calendar year, with no more than fifteen (15) months between assessments) develop and maintain a list of circuits that meet any of the criterion detailed in Requirement R6 that would be subject to Requirements R1 through R5 listed in PRC-023. This list shall be created annually and will include identification of the first calendar year for which the circuit meets any of the criterion described in Requirement R6. The list will be available on the MISO extranet site, which can be accessed via the link below.

- MISO ShareFile - PRC-023 List

M.1.3 Requirement R6.2

MISO shall make the list of circuits available at least once every calendar year, to all appropriate Regional Entities, Reliability Coordinators, Transmission Owner(s), Generator Owners, and Distribution Providers. The initial list of circuits shall be posted within thirty (30) calendar days of its establishment. If any change is made to the list of circuits, a new list shall be posted within thirty (30) calendar days of any such change. The list of circuits shall be posted in PDF format.

Expansion Planning shall also send a notification to all appropriate Regional Entities, Reliability Coordinators, Transmission Owner(s), Generator Owners, and Distribution Providers within thirty (30) calendar days of posting of the initial list or an updated list.

Transmission Owner(s) of circuits[i] to which the relay loadability standard (PRC-023) shall apply, as referenced by MISO Transmission Asset Management - Expansion Planning will also be identified in the published list.

Appendix N Transfer Capability Methodology

MISO documents its Transfer Capability Methodology applicable to the Near-Term Transmission Planning Horizon within this Appendix N of this BPM. MISO conducts its Near-Term (Years one through five) planning assessment based on powerflow simulations representative of various system conditions in five year out MISO Transmission Expansion Plan (MTEP) models. System conditions modeled in these models are normal base transfers representative of network operated to supply projected customer demands and projected Firm Transmission Services at forecasted system demands and consistent with applicable NERC Transmission Planning standards. By using these base MTEP models to conduct Transfer Capability analyses pursuant to the methodology documented below, MISO thus establishes Transfer Capability as an incremental transfer above these base level flows.

N.1 Transfer Capability Methodology

This Appendix N constitutes MISO's documented Transfer Capability methodology, which it uses to perform Transfer Capability Analysis in the Near-Term Transmission Planning Horizon when there is a need to perform such analysis. The need to perform such analysis will be determined and agreed upon between MISO and Stakeholders at the bi-monthly PSC meetings. This methodology includes the following information:

N.1.1 Transfer Selection Criteria

Prior to commencement of its annual MTEP Transmission Planning studies, MISO will collaborate with Stakeholders, through the PSC, to determine whether there is a need to run a Transfer Capability analysis. If the need is determined, MISO will develop a list of transfers to be assessed and the transfer analysis parameters to be used for the studies in collaboration with its planning stakeholders and notify stakeholders at the PSC. A First Contingency Incremental Transfer Capability (FCITC) for each studied transfer path shall be established based on the most limiting of the Steady State or Voltage Stability and Transient Stability verification analyses. These transfers will be selected based on the following criteria:

- **Demand Forecast**: Transfers simulating increases in demand shall be conducted on MTEP five year out Summer Peak case.
  - Within its footprint where demand forecasts have historically exceeded their previously forecasted 50/50 forecast more than once, MISO will test increase in demand up to but not limited to respective current 90/10 demand forecast in the Near-Term planning horizon.
  - Where supported by local regulatory agency requests on study of new customer demands above projected Load Forecast, specific increased

demand transfers will be included within MTEP scope upon review of planning stakeholders.

- **Economic Exchange of power between systems**: Transfers simulating increases in economic power transactions may result from various conditions. These conditions based on stakeholder input and review of historic and projected system uses will be simulated in MTEP five (5) year out off-peak or light load cases as applicable. Conditions to test economic transfers shall be based on:
  - Increase in low cost renewable generation in specified regions within the MISO footprint.
  - Increase in other low cost generation in specified regions depending on shifts in projected fuel prices.
  - When supported by local Load Serving Entities (LSEs) and Generation Owners (GOs), specific economic transfers will be included within MTEP scope, upon review of planning stakeholders.
- **Historic and Projected Transmission Usage**: Transfers simulating historic and projected transmission usage not otherwise incorporated under economic transfers will be developed on the following basis and studied in peak or off-peak base cases as applicable:
  - Where review of flows on critical interfaces monitored in real time and same facilities within applicable MTEP cases is determined to be measurably different, MISO will establish transfers to simulate flows consistent with historic flows. Projected system flows may be established where planned generation and load additions are determined to increase historic flows.
    - Critical Interfaces to be reviewed shall be established within each MTEP scope based on real time operations feedback.
    - Flows shall be deemed measurably different where planning case interface flow is more than five (>5%) percent lower than historic flows on the same interface.
- **Generation Forecast**: Transfers simulating reduced generation in specified systems where requested by Generation Owners will be included within MTEP scope upon review of planning stakeholders.

In accordance with this Transfer Capability Methodology, there could be multiple models used for performing Transfer Capability analysis (e.g., 2-year SPK, 5-year SPK, 5-year WPK, etc.), unless MISO and Stakeholders agree otherwise.

N.1.2 System Operating Limits (SOL)

Transfer capabilities shall respect all System Operating Limits (SOLs) defined in MISO's SOL/IROL methodology, as documented within Appendix L of this BPM.

N.1.3 Planning Practice Consistency

Assumptions and criteria used to perform transfer capability assessments shall be performed consistent with MISO's planning practices as documented in this BPM.

N.1.4 Assumptions and Criteria

Each of the assumptions and criteria used in performing the assessment outlined in requirements R1.4.1 through R1.4.7 shall be addressed as follows:

N.1.4.1 Generator Dispatch

Generation dispatch reflected in base MTEP cases is derived from a regional tiered merit order list. Future planned committed generation or generators with signed interconnection agreements are also included in the model. All existing generators with approved Attachment Y Notices will be modeled offline, beginning on either their suspension or retirement start date, based on the information provided by the Generator Owners through the System Support Resource (SSR) study process. Units with approved Attachment Y notices that have waived their interconnection rights (i.e., retired) will remain offline indefinitely. Units with approved Attachment Y notices that have not waived their interconnection rights (i.e., suspended) will remain offline for the first three (3) years following their start date and after the three (3) years they will be available for dispatch. Additional details on MTEP model generation dispatch is documented *under Section 4.3.3.2 of this BPM*.

N.1.4.2 Transmission System Topology

Projected transmission system topology in the five-year planning horizon including but not limited to long term planned Transmission Outages, additions, and retirements are reflected in MTEP base cases. Please *refer to Appendix L: MISO SOL – IROL Methodology of this BPM* in compliance with *FAC-010 and Section L3.1* for additional details on system topology.

N.1.4.3 System Demand

Load demand in MTEP base cases is based on the most probable (50/50) coincident load projection for each Transmission Owner service territory for the study horizon being analyzed.

The external area load is modeled as represented in the applicable MMWG cases. Load is modeled as a net of indirect demand-side management programs. Modeling of system demand consistent with MOD standards is reflected within MTEP base cases. Additional details on MTEP load modeling is documented *under Section 3.3.2 of this BPM*.

N.1.4.4Current approved and projected Transmission Uses

MTEP base cases reflect projected firm transmission uses between MISO system and adjacent non-MISO systems as derived from applicable ERAG models. Transfers will be simulated so as to not exceed MISO aggregate interchange with outside areas. Where transfers are established to increase flows to simulate projected transmission uses, MISO will establish known interfaces monitored in real time to establish transfer paths.

N.1.4.5 Parallel Path (loop flow) Adjustments

Because it is recognized that transfers occur on all transmission paths that are part of the eastern interconnected system, in establishing transfer capability, MISO will monitor and recognize neighboring or adjacent interconnected system limits. MISO will only report out on a facility under MISO functional control as limiting. Any facilities identified in adjacent neighboring systems will be honored and coordinated with those entities to confirm validity, but the actual tier-1 facility name will be removed from the final report.

N.1.4.6 Contingencies

All single-event contingencies (NERC category P1, P2, and P7) will be applied in testing transfer capability. In addition select single-event contingencies plus a single element maintenance outage will also be simulated in establishing transfer capability for off-peak conditions. Consideration of this select list of single-event contingencies plus a single element maintenance outage ensures that the more significant maintenance outages are accounted for in establishing transfer capability, but these types of contingencies will only be simulated in transfers studied in off-peak cases where maintenance outages are most likely. These single-event contingencies plus a maintenance outage will be selected based on the results of past MTEP planning studies.

Please *refer to Section L3.2 from Appendix L: MISO SOL – IROL Methodology of this BPM* in compliance *with FAC-010* for additional details on contingencies simulated.

N.1.4.7 Monitored Facilities

In addition to all BES elements monitored in MISO and adjacent seams areas, select Low Voltage facilities shall also be monitored. Low Voltage facilities identified pursuant to MISO Low Voltage Monitoring criteria documented in Appendix P of this BPM shall be included in monitored facility list.

N.1.5 Adjustment of Generation, Load or Both in Transfer Simulations

Generation dispatch used in simulating transfers shall be consistent with MISO planning practices of using a tiered regional merit order. At the Exporting (or Sending) area, higher cost Network Resources (NRs) shall be dispatched up to the limit of generating capacity prior to dispatching Energy Resources (ERs). A merit order based on generation costs derived from Ventyx© Powerbase data used in MTEP base case modeling shall be employed in selection of cheaper generation capacity within NRs and ERs. Similarly, higher cost generation in the importing area will be reduced to accommodate needed transfer levels. This will be accomplished by assigning participation factors to generators based on cost.
Where increases in demand are to be simulated in transfers, load at applicable stations will be increased maintaining respective modeled power factors.

N.2 Issuance of Methodology by PC

A notice of issuance of Transfer Capability Methodology shall be sent out in accordance *with Sections N2.1 and N2.2 of this Appendix N as shown below*.

N.2.1 Distribution of Transfer Capability Methodology

MISO will distribute its Transfer Capability Methodology to Planning Coordinators adjacent to or overlapping the MISO footprint. MISO will also distribute its Transfer Capability Methodology to each Transmission Planning Registered Entity within the MISO footprint. The most current list (at the time of communication) of PCs and TPs are listed on NERC registration site will be used.

N.2.2 Distribution to Other Entities

MISO will additionally distribute its Transfer Capability Methodology to each functional entity that has a reliability-related need for the Transfer Capability Methodology and submits a request for that methodology within thirty (30) Calendar Days of receiving that written request.

N.3 Response to comments

If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, MISO shall provide a documented response to that recipient within forty-five (45) Calendar Days of receipt of those comments. MISO shall indicate in its comments whether a change will be made to the Transfer Capability methodology and, if no change will be made to the Transfer Capability Methodology, the reason why.

The Transfer Capability analysis shall be performed when both MISO and Stakeholders decide that there is a need to perform such a study in the near-term or long-term planning horizon. The determination of list of transfers will be completed by the end of first quarter of each year via the

Planning Subcommittee meetings. In order to conduct transfer assessment, consistent with current methodology and allow sufficient time to conduct assessment, only revisions to Transfer Capability methodology made before the end of first quarter of each year shall apply to current year planning assessment. Revisions made after first quarter of each year shall apply to subsequent year assessments.

N.4 Annual assessment of Transfer Capability

As noted above, a collaboration between MISO and Stakeholders will be conducted to determine the need of conducting an assessment of Transfer Capability for each new MTEP cycle. Simulations in support of the assessment shall include at least one year in the Near-Term Transmission Planning Horizon with the year typically being the five (5) year out planning year.

N.5 Availability of Study Results

MISO shall make the documented Transfer Capability assessment results available within forty-five (45) Calendar Days of completion of the assessment to the recipients of its Transfer Capability methodology pursuant to *Sections N2.1 and N2.2 from this Appendix N of this BPM*.

Additionally, any functional entity that has a reliability related need for MISO Transfer Analysis assessment results and makes a written request for those results after the completion of the assessment, MISO will make available to that entity the results of its assessment within forty-five (45) Calendar Days of receipt of the request. In MISO’s determination of whether the functional entity has a reliability related need, to the extent the requesting entity does not have applicable confidentiality privileges, MISO will make available limited publicly available assessment results not subject to confidential information.

N.6 Availability of Study Related Data

Any entity receiving the results of MISO’s Transfer Analysis assessment requesting supporting data for the assessment results will be provided supporting data within forty-five (45) Calendar Days of receipt of request, subject to MISO legal and regulatory obligations regarding the disclosure of confidential and/or sensitive information.

Appendix O Coordination of Studies between MHEB, MPC, and MISO

The procedure will govern the TSR study coordination for the Long Term Firm Transmission Service Requests on MHEB, MPC and MISO transmission systems where one of the three parties may be an Affected System TSP for the TSR. The entire coordination procedure is documented in Appendix O of this BPM.

O.1 Purpose

The purpose of this coordination procedure is to coordinate Long Term Firm Transmission Service Requests where one of the three parties may be an Affected System. Each party will implement this procedure through Business Practices under each party's respective tariff(s).

O.2 Scope

A TSR is deemed within scope for this agreement as follows:

- MH will be considered an Affected System for TSRs requested under the MPC or Tariffs if the TSR has a POR or a POD from the following list:
  - ALTE, ALTW, CE, DPC, GRE, LES, MDU, MEC, MGE, MHEB, MP, MPC, MPW, NPPD, NSP, ONTW, OPPD, OTP, SMP, SPC, WAPA, WEC, WPS
- MPC will be considered an Affected System for TSRs requested under the MH or Tariffs if the TSR has a POR or a POD from the following list:
  - GRE, MDU, MHEB, MP, MPC, NSP, ONTW, OTP, SPC, WAPA
- MISO will be considered an Affected System for all TSRs requested under the MPC or MH tariff

A TSR that is deemed in scope will be subject to the coordination procedures below. If the TSR is not deemed in scope, it is not subject to the coordination procedures below.

O.3 Definitions

Affected System – a non-Host TSP whose transmission system may be reasonably expected to experience a non-trivial loading impact due to a TSR on a Host TSP's transmission system.

Affected System Upgrades – upgrades required to the Confirmed Affected System transmission system to accommodate the Host TSP TSR. The need for the Affected System

Upgrade will be identified in the impact study and further defined in the Affected System facilities study.

Confirmed Affected System – an Affected System that has been confirmed through either the Host TSP or the Affected System impact analysis that the Affected System has an impacted facility due to a TSR on a Host TSP's transmission system as shown in the Host TSP impact study report.

Host TSP – MH, MPC, or MISO that receives the TSR

Long Term Firm Transmission Service Request (TSR) – a request for long term firm transmission service across the TSP's transmission system under the respective party's tariff (MISO's tariff, MPC's Open Access Transmission Tariff (OATT), or MH's OATT)

Neighboring TSP(s) – MH, MPC, and/or MISO that does not receive the TSR. General reference to any or all of the parties to this coordination language.

as defined by the Tariff
Remedial Action Scheme – as defined by NERC standards

POR/POD – as defined by the Tariff

Transmission Service Provider or TSP – as defined by NERC standards

O.4 Procedure

MISO, MH, and MPC have agreed to the following process by which Long Term Firm Transmission Service Request studies are conducted to determine the impacts of TSRs on each other's transmission systems. Coordination with Affected Systems is required by the parties' respective tariffs. This joint coordination of TSR studies serves to clarify the process by which that coordination is conducted for MISO, MH, and MPC.

O.4.1 Notice

The Host TSP will provide notice of new TSRs which fall within the aforementioned scope *in Section O.2 to the Affected System(s)* once the TSR customer has signed an impact study agreement. The Host TSP will send an email with details of the associated TSR so that the Neighboring TSP can begin including the TSR in their models. The Host TSP will include the

Affected Systems in the ad-hoc study group for a Host TSP TSR impact study. This notice shall be provided regardless of whether the Affected System is also a Host TSP.

O.4.2 Impact Study Obligations

There are two coordination scenarios to consider for a TSR:

- When two or more of the parties are Host TSPs, and
- When only one of the parties is a Host TSP

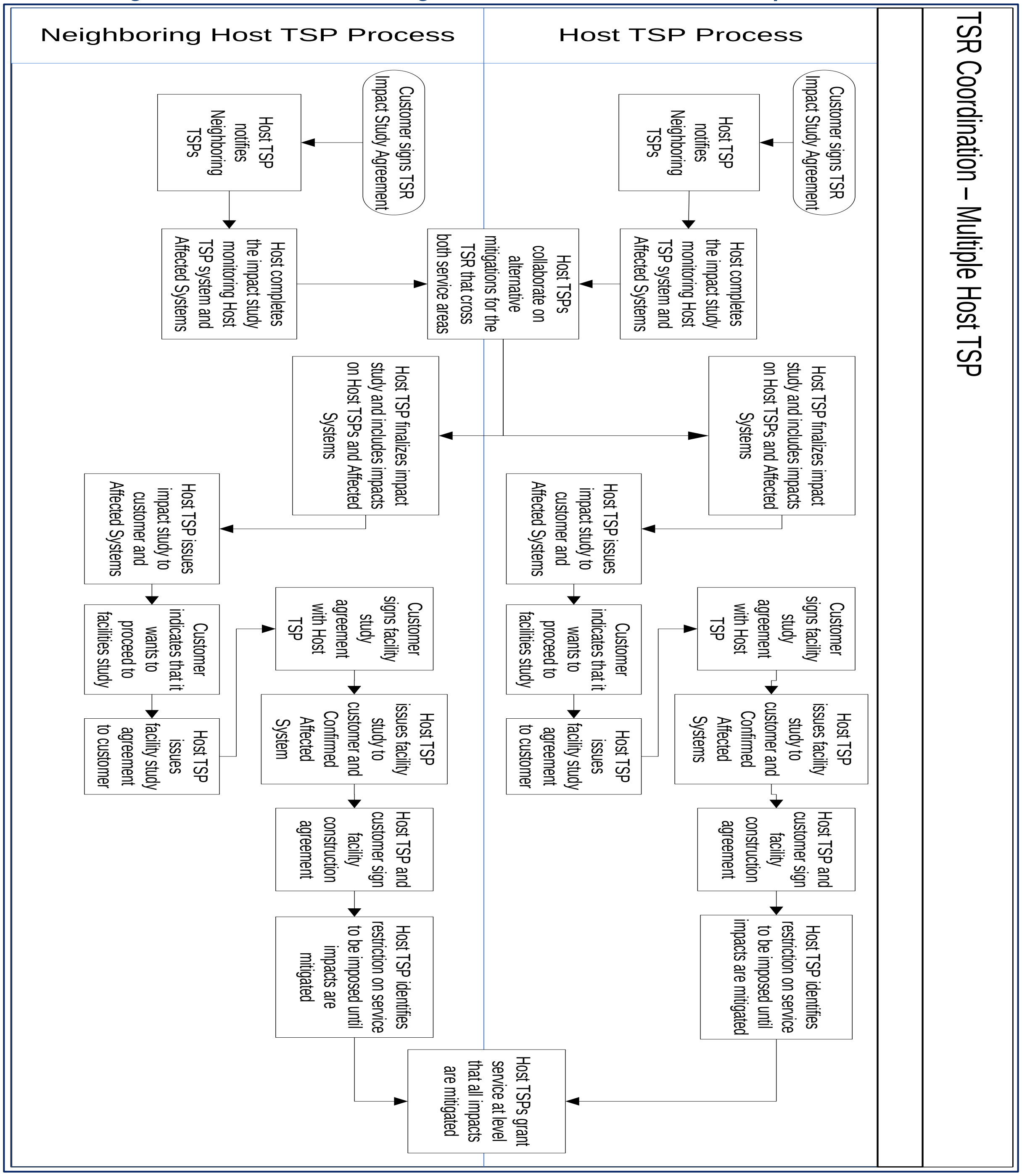
O.4.2.1 Process for a TSR that has more than one of the Neighboring TSPs as Host TSPs

The first scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from two or more TSPs which are parties in this coordination procedure. In this scenario the study to evaluate the impact of the TSR on the Host TSP's transmission system will be completed by each Host TSP as per the Host TSP's tariff, Business Practices, and study methodology.

If one of the Neighboring TSPs is a non-Host TSP, the non-Host TSP will be deemed an Affected System by each Host TSP and all associated provisions related to Affected Systems coordination will apply, as stated in the second scenario below.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

Figure O.4.2.1-1: Process diagram of TSR Coordination – Multiple Host TSP



O.4.2.2 Process for Affected System Coordination

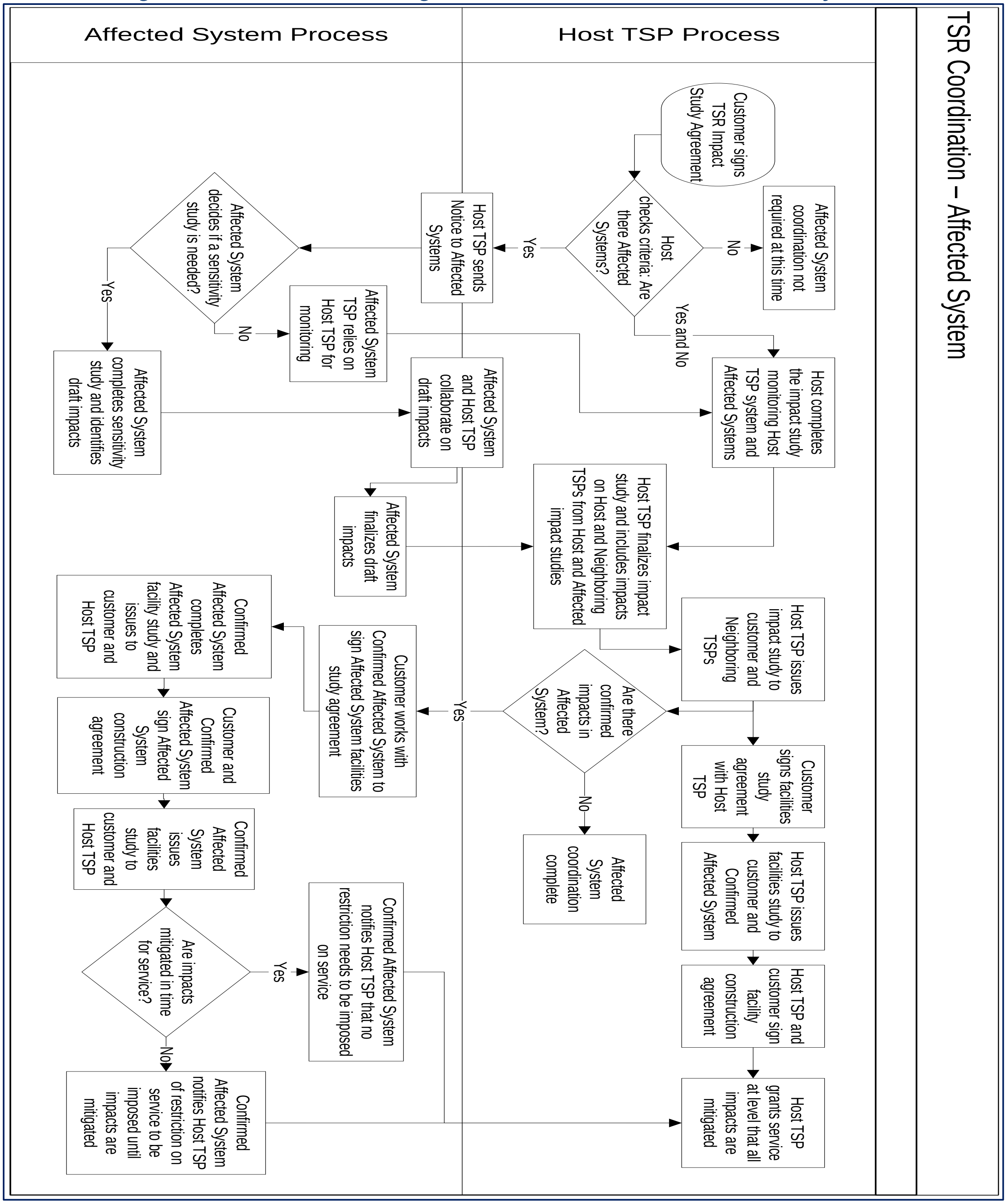
The second scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from only one of the TSPs party to this coordination procedure. This scenario also covers treatment of a non-Host TSP when there is a TSR coordinated between two Host TSPs. If a Neighboring TSP is deemed an Affected System in accordance with scope section, *Section O.2 of this BPM*, the Host TSP will include the Affected System(s) in the coordinated study process by providing Affected Systems with an opportunity to perform a sensitivity impact study on their own transmission system to be included in the Host TSP's impact study report. The Host TSP shall forward to the Affected System(s) the information necessary for the Affected System(s) to study the impact of the TSR on their respective transmission systems.

The Host TSP will accept study results from the Affected System(s) regarding the impact of the TSR on the Affected System's transmission system until a date ten (10) Calendar Days before the Host TSP's impact study is due to the TSR customer, provided that the Affected System will be allowed a minimum of forty-five (45) Calendar Days to complete their sensitivity study, unless otherwise agreed to. If the Host TSP determines that the study process is extended due to the complexity of the project, the same extension will be granted to the Affected System(s). Sensitivity studies conducted by Affected System(s) will use the methodology and criteria of the Affected System conducting the study.

The Affected System may either perform its own sensitivity study on the impact of the TSR on its transmission system for inclusion in the Host TSP's study report or may defer to the Host TSP's analysis for monitoring of its own transmission system. If the Affected System decides to perform its own sensitivity study, the time requirements for providing the results of the study to the Host TSP shall be as described above. If the Affected System's policies allow for the sharing of study models, a Customer can apply to obtain the study models from the Affected System by executing the required confidentiality agreements.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

Figure O.4.2.2-1: Process diagram of TSR Coordination – Affected System



O.4.2.3 General Impact Study Obligations

During the course of the TSR impact study for both scenarios, the Host TSP will monitor the Affected Systems' transmission systems and provide the draft results of potential impacts to the Affected Systems. When the Host TSP performs the impact study, the Host TSP will use reasonable efforts to monitor the affected system and:

- The MISO transmission owner study and reinforcement criteria will apply to the monitoring of MISO transmission facilities;
- The MPC study and reinforcement criteria will apply to the monitoring of MPC transmission facilities; and
- The MH study and reinforcement criteria will apply to the monitoring of MH transmission facilities.

If available, the Affected System will provide service limitation policies to the Customer upon request.

Potential impacts on the Neighboring TSP's transmission systems will be included in the Host TSP's impact study report along with any information regarding the validity of the impacts. Each Host TSP will coordinate with its Neighboring TSPs to develop alternatives to mitigate identified impacts. The Host TSP will include the following details provided by the Confirmed Affected System(s) in the Host TSP's impact study report:

- The minimum amount of transmission service that can be granted without Affected System Upgrades,
- A preliminary description of the required Affected System Upgrades,
- an estimated planning level cost, and
- Preliminary estimate of the in-service date of the system reinforcement

The Host TSP will refer the TSR customer to the Confirmed Affected System to begin the associated facilities study agreement process and construction of Affected System Upgrades for network reinforcements required on that transmission system.

The Host TSP will promptly share the study reports with the Affected Systems upon completion.

O.4.3 Mitigating Host TSP TSR on the Confirmed Affected System's Transmission System

If the transmission customer proceeds to the facilities study stage with the Host TSP (or to a service agreement if no facilities studies are necessary), notice will be provided by the Host TSP to any Confirmed Affected Systems. The tariff and Business Practices of an Affected System will apply to the identification and construction of Affected System Upgrades and/or implementation of other mitigation measures to address impacts to the Confirmed Affected System identified in the impact study.

The Host TSP and Confirmed Affected System will promptly share Facility Study reports with each other upon completion.

Transmission service will only be granted by the Host TSP up to the amount at which there are no transmission constraints identified by the studies on the transmission systems of the Confirmed Affected System(s). Partial transmission service may be granted if the Confirmed Affected System is not constrained at that level of service. The requested amount of transmission service can only be granted once all identified constraints on the system (MISO, MH, and MPC) have been mitigated.

If Confirmed Affected System(s) constraints are addressed through the use of alternative measures in lieu of constructing facilities, or as an interim measure while facilities are under construction, firm transmission service will not be granted beyond the amount permitted by the Confirmed Affected System's Business Practices.

O.5 Application and Governing Agreements

This coordination procedure applies to Manitoba Hydro (MH), Minnkota Power Cooperative (MPC), and the Midcontinent Independent System Operator (MISO). This procedure is effective as of the date this procedure is signed.

O.5.1 Governing Agreement for MPC and MISO Coordination

This coordination procedure is established between MPC and MISO pursuant to Sections 9.1 and 14.1 of the MISO-MPC Coordination Agreement.

O.5.2 Governing Agreement for MH and MISO Coordination

This coordination procedure is established between MH and MISO pursuant to Section 5.4 of the MISO-MH Coordination Agreement.

O.5.3 Governing Agreement for MPC and MH Coordination

This coordination procedure is established between MPC and MH pursuant to Sections 9.011, 9.02, and 9.022 of the Interconnection, Facilities and Coordinating Agreement respecting Ridgeway-Shannon 230 kV Interconnection.

Appendix P Methodology for Assessment of Low Voltage Facility Impacts on BES

P.1 Purpose

The assessment of impacts from low voltage sub-100 kV facilities on the Bulk Electric System is intended to identify facilities that pose a reliability risk and should be monitored/managed in MISO operations and planning processes. MISO planning analysis is performed to simulate contingent events that can cause overloads on the lower voltage system and subsequent tripping of facilities that result in BES overloads or system instability. This screening analysis is performed periodically (2-3 year cycle) to produce a list of the low voltage facilities that are candidates for monitoring and management by MISO. For each study cycle, the scope of the effort will be reviewed with the stakeholder community to allow opportunity to update elements of the study methodology and the assumptions included in the analysis.

P.2 Model Selection

The impact analysis will use existing MTEP models in order to expedite the model preparation work. Since these models have been reviewed and updated for use in the MTEP TPL compliance analysis, the models will require minimal modifications for use. Models will be posted for stakeholder review and will include a near term summer peak and a mid-term shoulder peak case that are intended to reflect the variations in dispatch associated with different types of Generation Resources such as higher wind conditions.

P.3 Monitoring and Contingency Set

All model elements 40 kV and higher in all MISO areas and first tier external areas will be monitored for screening. All 100 kV and higher branches in MISO and first tier areas will be included in the contingency set. N-1-1 contingencies are generated from the combinations of the elements included in the contingency set.

P.4 Contingency Screening

An initial contingency analysis run is performed on the contingent events to identify any pre-existing BES overloads that will be used later in differentiating new overloads from impacts on pre-existing (post-contingent) violations.

P.5 Cascading Analysis

The contingency process uses a customized script to implement event processing by the analytical engine which calculates the resulting post-contingent flows. This tool checks for subsequent loading exceeding one-hundred (100%) percent of emergency rating for low voltage facilities and one-hundred twenty-five (125%) percent for BES facilities or voltages outside of limits of the monitored facilities.

The process then tests any low voltage facility that is overloaded one-hundred (100%) percent by removing it from service, along with any BES facility loaded above one-hundred twenty-five (125%) percent, and attempts a power flow solution. If the power flow does not solve, the low voltage facility that was tested is flagged as a potential stability issue. If the power flow does solve, further overloads are checked to determine if a BES overload occurs, low voltages below 0.7 p.u. exist, or if the trip of the low voltage facilities causes cascading overloads on the remaining low voltage circuits. BES overloads are compared against the pre- overloads existing (not caused by the low voltage facility trip). If a new BES overload exists, the low voltage facility is flagged as having a BES impact. Any pre-existing overload is checked to determine if the change in flow is greater than five (>5%) percent. The analysis continues by tripping further overloaded low voltage facilities as well as any BES facility that is greater than one-hundred twenty-five (>125%) percent of the emergency rating. If a subsequent unsolved power flow case, low voltages below 0.7 p.u. exist or BES overload occurs, the low voltage facility is flagged as having a BES impact.

Low voltage facilities are further analyzed to determine if the LODF of the BES contingency elements on the low voltage facility exceeds three (3%) percent. If the LODF is less than three (<3%) percent the low voltage facility is excluded from the candidate list.

P.6 Post Analysis Review and Available Mitigation Plan

The results from the analysis are posted to the MISO planning ftp site for review and validation by Asset Owners. For results that are determined to be invalid (incorrect ratings/contingency definitions, etc.), the facilities are removed from consideration. Facilities with a documented operating action (reconfiguration) will be monitored but not managed. Facilities that do not have a documented mitigation plan will be evaluated to determine if market dispatch will be effective in managing congestion.

P.7 Dispatch Responsiveness

Dispatch responsiveness tests each candidate low voltage facilities without a mitigation plan to determine if MISO generation can be effectively used to manage the flow on the facility. Analysis of the facilities in the immediate and surrounding areas is performed to determine all contingent elements that have a three (3%) percent LODF on the low voltage candidate facility. The contingency elements are combined to produce double contingency events which are used to calculate the generator sensitivities for all MISO generators on the associated low voltage facility/contingent event. Generator sensitivities with at least a one and half (1.5%) percent impact on the candidate facility are used to determine the units to consider in re-dispatch. The total impact of dispatch is calculated as the sum of all the MISO dispatchable generation with at least one and half (1.5%) percent sensitivity multiplied by the modeled P_{max} of the units.

P.8 Candidate Selection

Facilities where the total impact of the generation dispatch is greater than twenty-five (25%) percent are then selected for congestion management. If total impact of the generation dispatch responsiveness does not meet the threshold of twenty-five (25%) percent of the low voltage facility emergency rating, an operating guide will be needed to manage the risk of overload.

P.9 Treatment in MISO Operations and Planning Processes

Candidate facilities meet the selection criteria for BES impacts will be monitored in MISO Operations and Planning Processes. If a candidate facility has met the Dispatch Responsiveness test and has not operational mitigation plan, it will be included for congestion management. Otherwise the facility will be monitored in security analysis to provide awareness of the potential reliability issues that may require mitigating actions. Candidate facilities will be monitored in MISO MTEP planning analysis for overloads and, if overloaded, will be analyzed further to determine if tripping of the facility causes an impact on the BES Transmission System. MISO will plan for BES Transmission System upgrades necessary to address the BES issues but will not plan for upgrades to non-transferred low voltage facilities. However, a facility owner may choose to pursue a more cost effective alternative low voltage transmission solution if it eliminates the risks to the BES Transmission System.

Figure P.9-1: Overall Process Steps

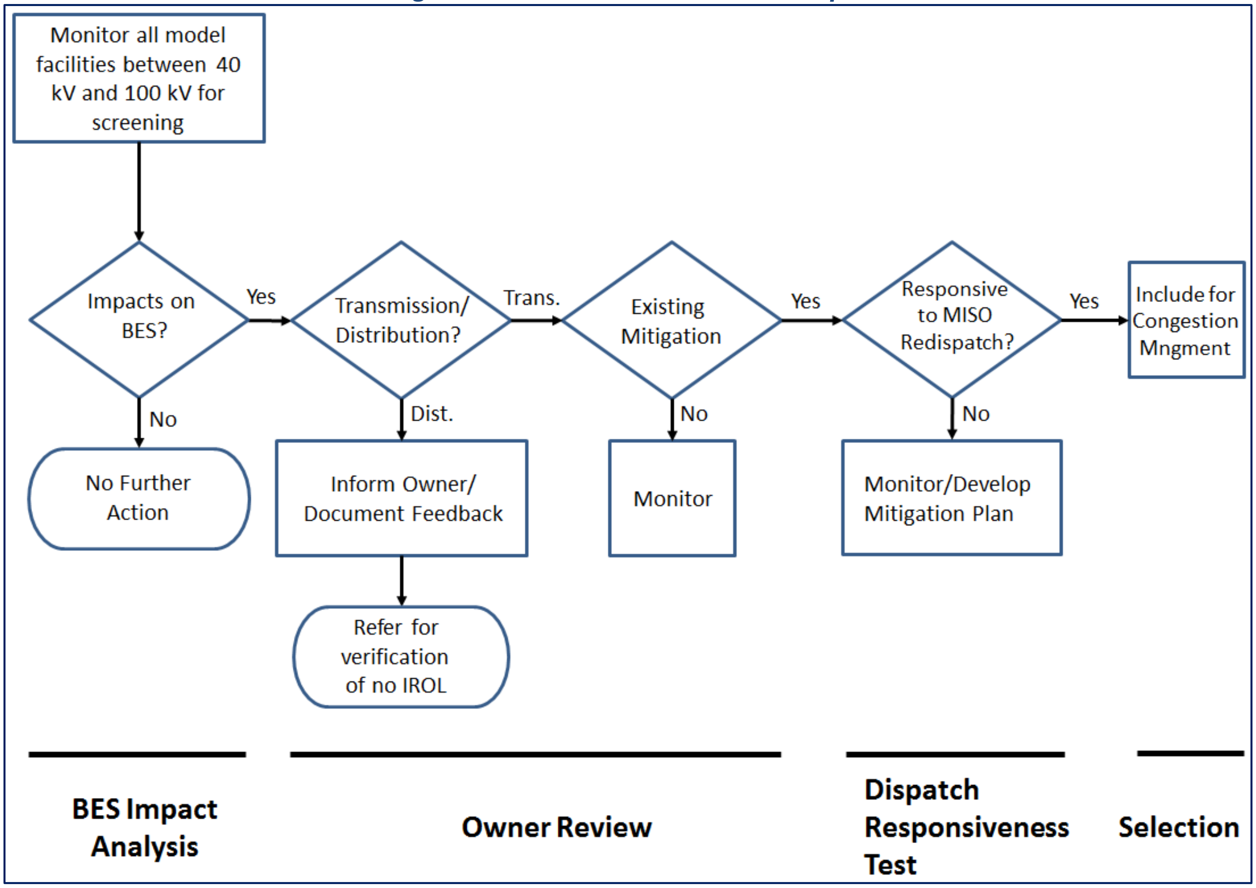


Figure P.9-2: BES Impact Analysis

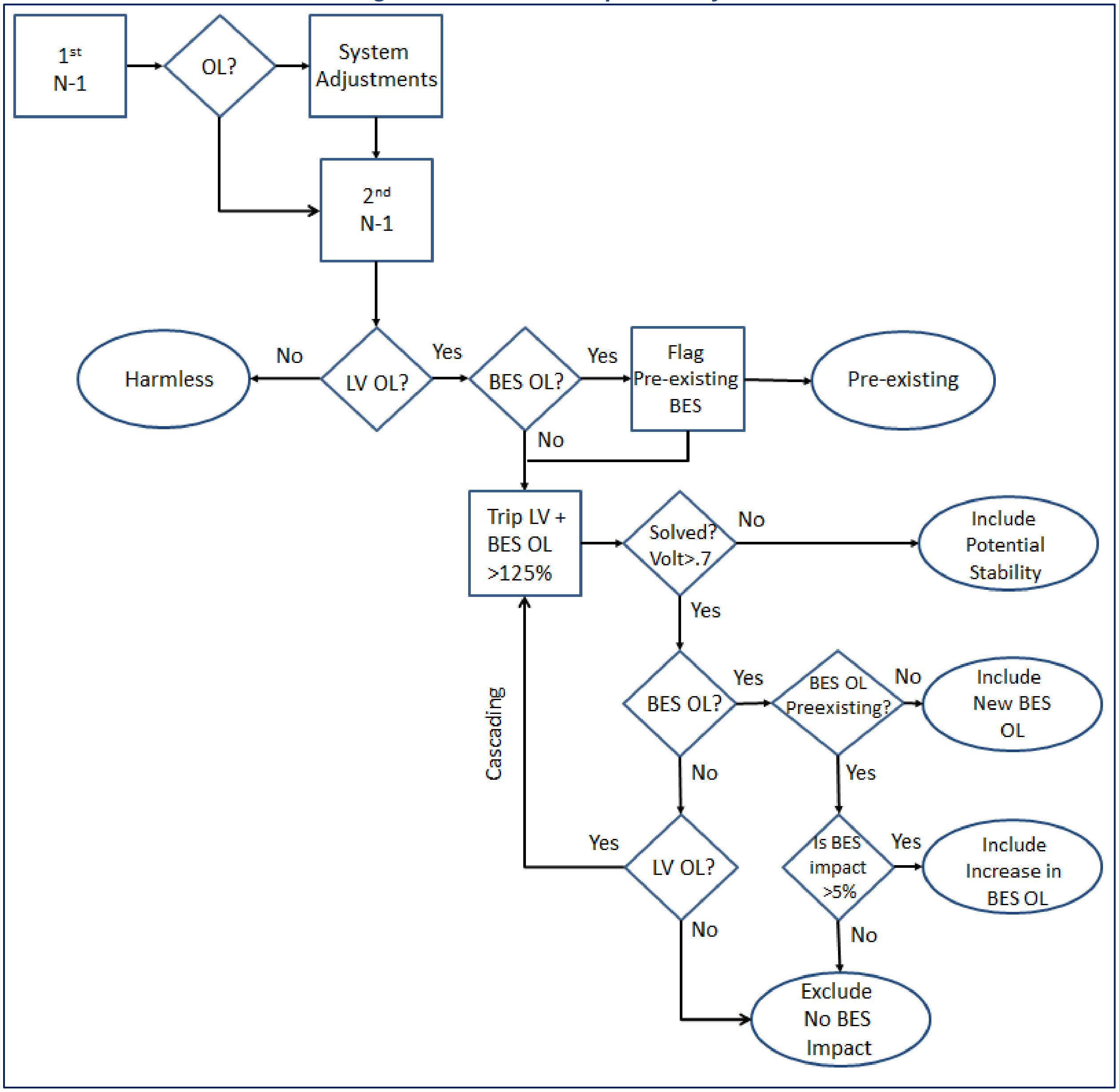
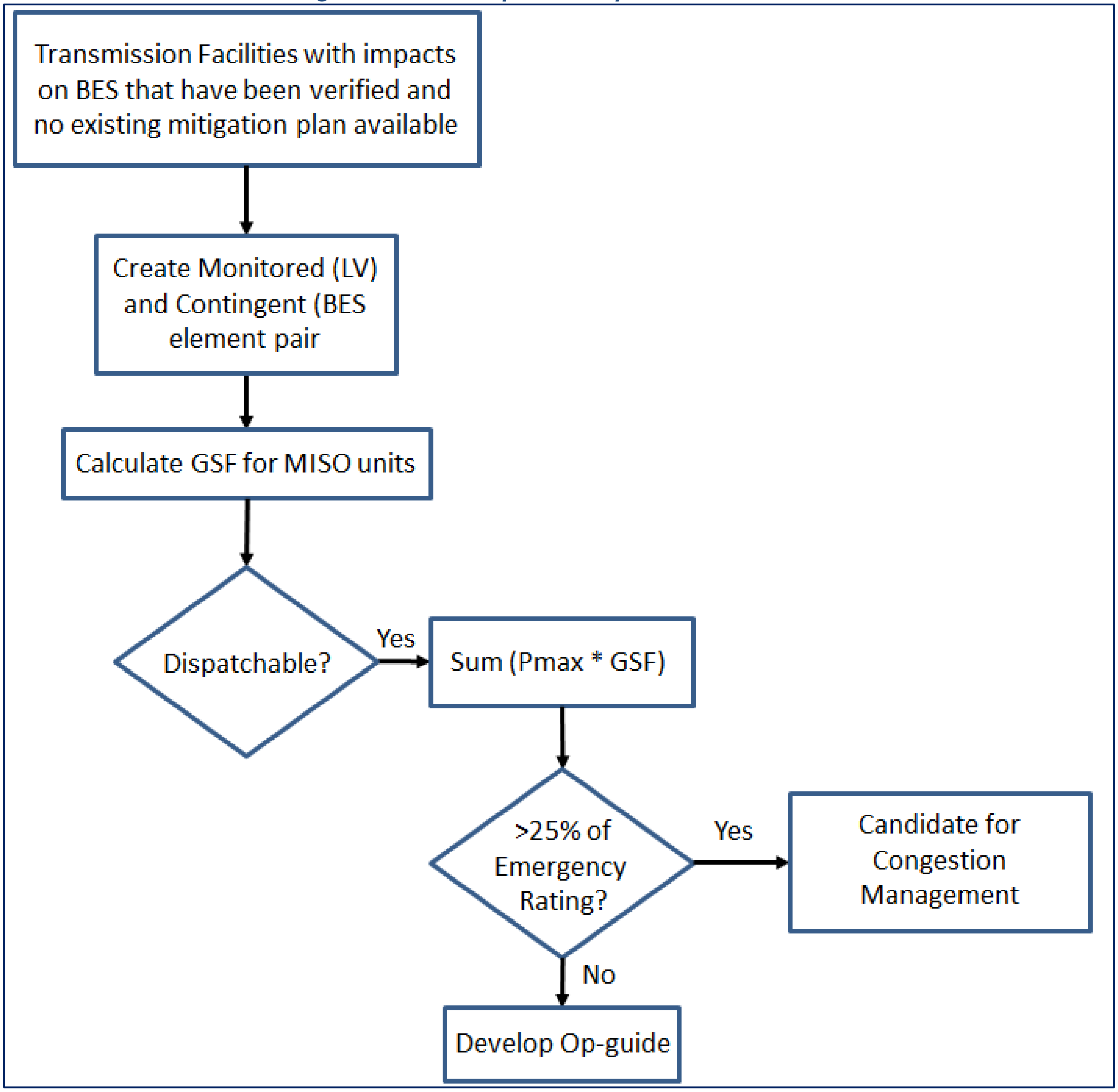


Figure P.9-3: Dispatch Responsiveness Test



P.10 Example of Impact Analysis on the MISO BES

- **Example 1:** *New BES overload caused by low voltage facility trip*
  - Contingency *Black-Orange 345 kV line No. 1* & Contingency *Red-Grey 138 kV line No. 2*
  - 1st N-1 contingency (Op. 10), open *Black–Orange 345 kV line No. 1*
  - No violations after 1st N-1 contingency
  - 2nd N-1 contingency (Op. 24), open *Red-Grey 138 kV line No. 1*
  - Violations after 2nd N-1 contingency
  - Voltage Violation, voltage level on the *East 138 kV Bus* is 0.88 p.u. (<0.9 by 0.02).
  - Thermal Violation, loading on the *West Sub M-West Sub N 69 kV line No. 1* is 54 MVA (114.9%, 47 MVA)
  - A 69 kV facility overload caused by the initial contingencies that are tripped in the subsequent cascading test.
  - **Step 1**: Remove the *West Sub M-West Sub N 69 kV line No. 1*
    - Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.84 p.u. (<0.9 by 0.06)
    - Voltage Violation, voltage level on the *East Sub P 69 kV Bus* is 0.89 p.u. (<0.9 by 0.01)
    - Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 234 MVA (101.7%, 230 MVA)

New BES overloads results from the trip of the LV facility so cascading test is terminated. The new BES overload resulting from the low voltage facility trip passes impact criteria and the low voltage facility of the *West Sub M-West Sub N 69 kV line No. 1* is evaluated for LODF impact. LODF for the contingent element *Black–Orange 345 kV line No. 1* on the *West Sub M-West Sub N 69 kV line No. 1* facility is greater than three (>3%) percent so facility is included as candidate for monitoring.

- **Example 2:** incremental overload greater than five (>5%) percent of pre-existing BES overload
  - 'Contingency *Red-Blue 345 kV line No. 1* & Contingency *Yellow-Green 138 kV line No. 2*
  - 1st N-1 contingency (Op. 1), Open the *Red-Blue 345 kV line No. 1*
  - No violations after 1st N-1 Contingency (Op. 1)
  - 2nd N-1 contingency (Op. 17), Open the *Yellow-Green 138 kV line No. 1*
  - Violations after 2nd N-1 contingency:

- Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.89 p.u. (<0.9 by 0.01)
- Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 240 MVA (104.3%, 230 MVA)
- Thermal Violation, loading on the *West Sub C-West Sub D 69 kV line No. 1* is 38 MVA (108.6%, 35 MVA)

Since *East Sub A-East Sub B 138 kV line No. 1* is a BES overload as a result of the initial BES contingencies this is flagged as pre-existing and not caused by the subsequent trip of the low voltage facility in subsequent steps. However, the 69 kV facility overload caused by the initial contingencies is tripped in the subsequent cascading test.

- **Step 1**: Remove the *West Sub C-West Sub D 69 kV line No. 1*
  - Voltage Violation, voltage level on the *East Sub Q 138 kV Bus* is 0.86 p.u. (<0.9 by 0.04)
  - Voltage Violation, voltage level in the *East Sub R 69 kV Bus* is 0.87 p.u.(<0.9 by 0.03)
  - Thermal Violation, loading on the *East Sub A-East Sub B 138 kV line No. 1* is 252 MVA (109.6%, 230 MVA)

No new BES overloads result from the trip of the LV facility and no further overloading occurs on the 69 kV facilities so the cascading test is ended. However, since the overload on the *East Sub A-East Sub B 138 kV line No. 1* is further increased by five (5%) percent, this passes the impact criteria and the low voltage facility of the *West Sub C-West Sub D 69 kV line No. 1* is evaluated for LODF impact. LODF for the contingent element *Yellow-Green 138 kV line No. 1* on the *West Sub C-West Sub D 69 kV line No. 1* facility is greater than three (>3%) percent so facility is included as candidate for monitoring.