Hoosier Energy REC
2014 Integrated Resource Plan
Volume III: Appendices
Redacted Version

November 2014

Prepared By:

Hoosier Energy Rural Electric Cooperative, Inc.
P.O. Box 908
Bloomington, IN 47402

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Appendix H

FERC Form 715

Appendix H –
FERC Form 715 - Part 1

FERC Form 715 Overview

Parts 2, 3, and 6 May Contain Critical Energy Infrastructure Information - Do Not Release

FERC Form 715

MISO Region - April 1, 2014

Part 1: Identification and Certification	
Transmitting Utility Name	**Hoosier Energy**
Transmitting Utility Mailing Address	**7398 North State Road 37** **P.O. Box 908** **Bloomington, IN 47402-0908**
Contact Person Name	**Chris Ware / Todd Taft**
Title	**PE / System Planning Engineer**
Telephone Number	**(812) 876-0366 / (812) 876-0539**
FAX Number	

*The Certifying signature below (row 22) is that of the authorized Respondant official who certifies the accuracy of the information submitted, and also authorizes the MISO to consent to release of this filing to third parties pursuant to FERC CEII disclosure policy and subject to any exceptions noted in row 21 of this form.**

Objections or other conditions related to the MISO's release of information contained in this filing to third parties.	NONE
Certifying Official Signature	
Name (please print)	**Todd Taft**
Title	**Planning Engineer**

Part 2:				
the Respondent authorizes the MISO to submit powerflow information in the Respondent's behalf. Regional contact information is as follows:	**Yes**	**X**	**No**	
Regional Organization	MISO			
Mailing Address	MISO P.O. Box 4202 Carmel, IN 46082-4202			
Contact Person	Ben Stearney			
Contact Person Title	Engineer II			
Contact Person Telephone Number	651-632-8414			
Contact Person email	bstearney@misoenergy.org			

Power Flow Cases Available are 2013 MISO MISO Transmission Expansion Plan (MTEP) Models
MTEP13-2015SUM-SCED_Phase2_FINALrev1_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav
MTEP13-2018-19_Winter_700MWNorthFlow_Phase2_Final_rev1_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav
MTEP13-2018Shoulder-SCED_Phase2Final_rev1_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav
MTEP13-2018SUM-SCED_Phase2_Finalrev1_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav
MTEP13-2023SShoulder-SCED_Phase2_Final_rev2_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav
MTEP13-2023SUM_SCED_Phase2_Final_Rev3_bk_CONTAINS_CEII_DO_NOT_RELEASE.sav

Respondent authorizes the MISO to submit the Resondant's system representation that exists in the curent MISO MTEP models	**Yes**	**X**	**No**	
Respondent will submit additional powerflow information other than the above MISO MTEP models	**Yes**		**No**	**X**

Respondent does not authorize the MISO to submit its system representation that exists in the MISO MTEP models and will submit its own powerflow information	Yes		No	X
Respondent authorizes the MISO to submit a data dictionary referencing power flow bus names with long English names and EIA plant codes	Yes	X	No	
Part 3: Transmitting Utility Map and Diagrams				
Respondent authorizes the MISO to submit a regional bulk transmission Planning map that includes the respondent's bulk transmission system	Yes	X	No	
Respondent authorizes the MISO to submit the respondent's transmission Planning maps that have been provided to the MISO	Yes	X	No	
Respondent will submit additional maps	Yes		No	X
Part 4: Transmission Planning Reliability Criteria**				
Respondent employs NERC Transmission Planning Standards TPL-001-0.1 , TPL-002-0 , TPL-003-0, and TPL-004-0. FAC-010-2, and NUC-001-2 are also applicable to an RC or TP. RTO and RRO, State, and MISO Member (Local) planning criteria are also used. MISO will submit the applicable criteria following FERC instructions.	Yes	X	No	
Respondent will submit criteria in addition to that submitted by MISO.	Yes		No	X
Respondent will submit its own criteria	Yes		No	X
Part 5: Transmission Planning Assessment Practices**				
Respondent endorsess the MISO Transmission Planning Assessment Practices used in the MTEP, and authorizes the MISO to submit the MISO Planning Business practices document (Assessment Practices) in respondent's behalf.	Yes	X	No	
Respondent will submit Assessment Practices in addition those of the MISO	Yes		No	X
Respondent will submit its own Assessment Practices	Yes		No	X
Part 6: Evaluation of Transmission System Performance				
Respondent cities the Annual MISO MTEP report, including Appendices A, B, C, D1, D2, D3, D4, D5 and D8 as a satisfactory evaluation of the performance of its portion of the transmission system, and authorizes the MISO to submit this report in respondent's behalf.	Yes	X	No	
Respondent will submit its own evaluation	Yes		No	X

*Tranmission planning data is submitted to the MISO for the MISO's further submission as part of the Regional FERC Form 715 filing being made on behalf of Transmission Owning members of the MISO. Parts of this filing contain CEII as marked. Data provided by Transmission Owners marked as CEII will not be used for any other purpose by the MISO unless specifically authorized. FERC Form 715 data as submitted may contain data regarding the electric system of partys other than the responding Transmission Owner. There are no representations made regarding the accuracy of any other party's data included in this filing. In addition, the MISO's policy on disclosure of FERC Form 715 data to FERC is: Upon notification of a third party request to FERC for disclosure of this filing and subject to satisfaction of all other appropriate FERC CEII disclosure requirements, the MISO is authorized to and will consent to such disclosure.

Appendix H
FERC Form 715 – Part 2

Hoosier Energy Transmission System
Power Flow Data

Redacted

Appendix H
FERC Form 715 – Part 3

Hoosier Energy Transmission System Maps

Redacted

Appendix H
FERC Form 715 – Part 4

Transmission Planning Criteria and Facility Rating Methodology

Federal Energy Regulatory Commission

Form 715
Annual Transmission Planning
and Evaluation Report

Part IV
Transmission Planning Criteria

As a regular member of the Reliability*First* Corporation, Hoosier Energy REC, Inc. has adopted and adheres to the principles and procedures as outlined in the following R*F*C compliance standards:

- TPL-001
- TPL-002
- TPL-003
- TPL-004
- MOD-011
- MOD-013

See attached copies of Reliability*First* compliance standards.

Additionally, Hoosier Energy REC, Inc. utilizes internally developed planning criteria. It is HE's practice to incorporate voltage limits of 95% to 105% unit voltage under normal conditions, and 90% to 110% unit voltage under contingency and stressed conditions. HE's thermal limit practice is to allow transformers and transmission lines to reach 100% of the 'A' or 'normal' rating during normal operation and 100% of the 'B' or 'emergency' rating during contingency or stressed conditions.

See attached document "FacilityRatingMethodology_HoosierEnergy5-Feb-08.doc" for further details regarding the rating of Hoosier Energy REC, Inc. equipment and facilities.

FACILITY RATING METHODOLOGY – HOOSIER ENERGY REC, INC.

Last Revised 5-Feb-08

The criteria utilized for planning the system at the primary level are based on the ECAR standards as listed in the North American Electric Reliability Council's "Planning Standards." In essence, the applicable ratings refer to the facility thermal ratings as determined and consistently applied based on standard industry engineering standards. Hoosier Energy uses the IEEE "Guide for Loading Mineral-Oil-Immersed Transformers" Std C57.91-1995 for determining allowable transformer loading and the ECAR "Transmission Conductors Thermal Ratings" 89-TFP-28 for line loadings.

Transmission Line Conductor Rating Methodology – Overhead

The line ratings are determined by using the calculations found in the ECAR conductor thermal rating report. The line ratings are based on the design temperature, which will be 50°C, 80°C or 100°C depending on the particular line design, and assume a wind speed of 2.2 miles/hour and ambient temperatures of 32°C for summer and 0°C for winter. Additional factors assumed in the line ratings are the solar absorption factor of 0.8, the emmissivity factor of 0.8, and the wind to conductor angle of 90 degrees. HE does not employ a different emergency rating for transmission lines.

Transmission Line Conductor Rating Methodology – Underground

Hoosier Energy REC, Inc. does not employ any underground transmission line conductor at this time. No methodology has been developed. Should HE employ any underground transmission lines in the future, a rating methodology will be developed at that time.

Power Transformer Rating Methodology

The ratings for the transformers are specific to each unit's heating characteristics and are based on hot-spot temperatures not exceed 120°C. Ambient temperatures are assumed to be 40°C in summer and 10°C in winter. The normal rating assumes that the hourly transformer loading will follow a typical daily load curve with off-peak hour loads about 50-60% of the peak hour load. As a result, the normal ratings are approximately 115% of nameplate for summer and 145% of nameplate for winter. The emergency limits assume that the transformers will be loaded to some point above normal for an twenty-four hour period with the hot-spot temperature not to exceed 180°C. In some cases, the top-oil temperature of 105°C is the limiting factor. Given these parameters, the emergency summer ratings are typically 140% of nameplate and the emergency winter ratings are typically 200% of nameplate.

Substation Bus Conductor Rating Methodology

Substation Bus Conductor is rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Substation Bus Conductor.

Circuit Breaker Rating Methodology

Circuit Breakers are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Circuit Breakers.

Substation Bus Switch Rating Methodology

Substation Bus Switches are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Substation Bus Switches.

Transmission Line Switch Rating Methodology

Transmission Line Switches are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Transmission Line Switches.

Current Transformer Rating Methodology

Current Transformers are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Current Transformers.

Additionally, CT selection is based on the requirements of each circuit on a case-by-case basis. The Protection Engineer uses good engineering practices in the selection of each CT. It is the engineer's responsibility to verify the CT is sufficiently robust to meet the needs of the circuit based on the nameplate rating of the component.

Relay Rating Methodology, including thermal and trip setting considerations.

Relays are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Relays.

Additionally, relay selection is based on the requirements of each circuit on a case-by-case basis. The Protection Engineer uses good engineering practices in the selection of each relay. It is the engineer's responsibility to verify the relay is sufficiently robust to meet the needs of the circuit based on the nameplate rating of the component.

Metering Rating Methodology, including thermal and scale considerations.

Meters are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of meters.

Additionally, meter selection is based on the requirements of each circuit on a case-by-case basis. The Protection Engineer uses good engineering practices in the selection of each meter. It is the engineer's responsibility to verify the meter is sufficiently robust to meet the needs of the circuit based on the nameplate rating of the component.

Wave Trap Rating Methodology

Wave Traps are rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of Wave Traps

Rating Methodology for Other Series Elements

All other series element equipment is rated according to the manufacturers recommended nameplate ratings. HE employs the substation design criteria as defined in the NRECA "Design Guide for Rural Substations – Project 97-22" dated 10/99. Nameplate rating values are used for all applications (summer, winter, normal, and emergency) in the design and rating of all other series elements.

Database and/or Listing of Ratings

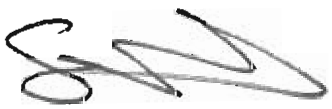
HE maintains a database in the form of an excel spreadsheet. This spreadsheet is reviewed and updated as needed annually by the planning engineering department. The spreadsheet is titled "HE_CompspecXXXX_VX – Where latest revision is annotated with year and revision number – see \\BNT1\BPLAN\NERC\RFC BCD & Compliance\HE_compspec2008_V1.xls for latest revision. Further information can be found in the Cascade CMMS Database

The 'HE_Compspec' spreadsheet captures all terminal equipment for each line segment and facility. The component with the lowest rating or the most limiting element is to determine the rating of the entire line segment or facility.

The ratings of facility equipment are verified annually by the Planning Engineer. Protection systems and control settings for terminal equipment protection are reviewed annually by the Protection Engineer. These protection limits will be considered as terminal equipment ratings in the most limiting element analysis.

All inter-area tie line, jointly-operated, and jointly-owned facility ratings are reviewed on an annual basis. The Planning Engineer will coordinate these ratings with planning counterparts at neighboring facilities annually at a minimum. The ratings will be cross referenced and verified so that a single rating set results.

Prepared by Lou Magyar



5-Feb-2008

Appendix H
FERC Form 715 – Part 5

MISO Business Practices Manual – Transmission Planning

Manual No. 020

Business Practices Manual
Transmission Planning

Disclaimer

This document is prepared for informational purposes only to support the application of the provisions of the Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) of the Midcontinent Independent System Operator, Inc., (MISO), and the services provided under the Tariff. MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website, in conjunction with the Tariff and other applicable procedures, including, but not limited to, the applicable NERC Reliability Standards as they may be revised from time to time. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff. MISO is not responsible for any reliance on this document by others, or for any errors or omissions or misleading information contained herein.

This Business Practices Manual (BPM) contains information to augment the filed and accepted Tariff. In all cases the Tariff is the governing document and not the BPMs. Additionally, if not otherwise defined herein, all capitalized terms in this BPM have the meaning as defined in the Tariff.

Time Zone

In 2006, Central Indiana, where MISO offices are located, began observing Daylight Savings Time. However, MISO, its systems, and the Midwest Markets, will continue to do business in Eastern Standard Time year-round.

Revision History

Document Number	Reason for Issue	Revised by:	Effective Date
BPM-020-r9	Updates include the following items: 1.) Annual Review Completed 2.) Section 4.3.4: Review of Market Participant Funded Projects section added 3.) Appendix J, Section 5.1.1 thru 5.3: Revised language regarding upgrades based on outages during maintenance periods 4.) Appendix L: Revised SOL identification methodology 5.) Appendix M: Revised to update methodology for new standard PRC-023-2 6.) Appendix N: Added new methodology for FAC-013-2: Transfer capability performed in the planning horizon	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.) Annual review completed 2.) Section 2.4.1.3 – New MEP cost allocation 3.) Section 7 – GIP, MEP and MVP cost allocation updates; cost shared projects 4.) Remove Section 6 – Generator Interconnection Planning – Duplicate section in BPM-015, owned by the Generator Interconnection Planning Department	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	Section 5: Long Term Transmission Services	P. Muncy/ M. Sutton	SEP-22-2011

BPM-020-r4	Updates include the following items: 3) Multi Value Project Cost Allocation criteria and methodology 4) Shared Network Upgrade methodology 5) Regionally Beneficial Project name change to Market Efficiency Project Reflects Tariff revisions with an effective date of July 16, 2010.	M. Tackett	MAR-09-2011
BPM-020-r3	Appendix J: Additional Language on system reconfiguration and redispatch evaluation for Category C3 events for LODF Calculation Section 2.6.1: Expand on MISO Transmission Provider responsibilities 1) 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 JUN-16-2010	A. Dortch	JUL-08-2009
TP-BPM-002-r1	Section 4.3.6: Language Changes in MTEP Contingency Selection Process Section 4.3.7.1: Language Changes in MTEP IROL Identification Process Section 4.3.7.8: New Language describing process for planning for feasibility of LTTR's Appendix J: Additional Language on 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 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 MISO markets, provisions of transmission reliability services, and compliance with MISO settlements, billing, and accounting requirements.

1.2 Purpose of this Business Practices Manual

This *BPM for Transmission Planning* describes MISO's transmission planning process. Also included in this BPM are the former *BPM for Transmission Services, BPM-013,* and *BPM for Generation Interconnection, BPM-015.*

1.3 References

Other reference information related to this BPM includes:

- MISO Tariff (Tariff)
- Agreement of the Transmission Facilities Owners to Organize The Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation ("MISO Agreement")
- Other BPMs

1.4 MISO Planning Contacts

MISO planning staff contact details for specific planning functions Contact Client Relations.
https://www.misoenergy.org/StakeholderCenter/ClientRelations/Pages/ClientRelations.aspx

1.5 Defined Terms used in the BPM for Transmission Planning

The following defined terms are used through the BPM for Transmission Planning:

- **Coupled Transmission Issue.** A Transmission Issue that either shares the same root cause as another Transmission Issue or has a solution that is common to another Transmission Issue.
- **Decoupled Transmission Issue.** A Transmission Issue that does not share the same root cause as any other Transmission Issue and does not have a solution that is common to any other Transmission Issue.
- **Dependent Transmission Project.** A proposed transmission expansion project that resolves at least one Coupled Transmission Issue.
- **Non-dependent Transmission Project.** A proposed transmission expansion project that resolves only a Decoupled Transmission Issue and thus can be evaluated independently of the evaluation of proposed solutions to other Transmission Issues.
- **Short-term Transmission Plan.** The group of transmission projects recommended for inclusion in Appendix A in a specific MTEP cycle.
- **Total Plan Benefit-to-cost Ratio.** The benefit-to-cost ratio associated with a specific Short-term Transmission Plan and defined as the ratio of the present value of the total benefit of the Short-term Transmission Plan evaluated over the first twenty years of the Short-term Transmission Plan's life to the present value of the annual revenue requirements of the Short-term Transmission Plan evaluated over the first twenty years of the Short-term Transmission Plan's life.
- **Total Plan Value.** The total value generated by a specific Short-term Transmission Plan and defined as the difference between of the present value of the total benefit of the Short-term Transmission Plan evaluated over the first twenty years of the Short-term Transmission Plan's life and the present value of the annual revenue requirements of the Short-term Transmission Plan evaluated over the first twenty years of the Short-term Transmission Plan's life.
- **Transmission Issue:** A reason to improve, expand or modify the Transmission System. These reasons may be compliance-based, economic-based, or reflect other local needs. Compliance-based reasons reflect the need to comply with all requirements imposed on the Transmission System performance by entities with jurisdiction or authority over all or part of the Transmission System including, but not necessarily limited to, i) compliance with Applicable Reliability Standards including

NERC standards and applicable Regional Entity standards, ii) compliance with local reliability standards and requirements when applicable, iii) compliance with Transmission Owner standards if applicable, iv) compliance with applicable state and federal laws and v) compliance with applicable regulatory mandates and obligations, including regulatory obligations related to serving load, interconnecting generation and providing transmission service. Economic-based reasons reflect the opportunity or obligation to provide added economic value to Transmission Customers through specific expansions of the Transmission System, where added economic value is the difference between the financially quantifiable benefits associated with specific expansions to the Transmission System and the financially quantifiable costs of those expansions. Economic value may be incremental to the value achieved from meeting a compliance requirement, or may stand on its own.

- **Transmission Compliance Issue.** A Transmission Issue resulting from the need to comply with all requirements imposed on the Transmission System performance by entities with jurisdiction or authority over all or part of the Transmission System including, but not necessarily limited to, i) compliance with Applicable Reliability Standards including NERC standards and applicable Regional Entity standards, ii) compliance with local reliability standards and requirements when applicable, iii) compliance with Transmission Owner standards and criteria if applicable, iv) compliance with applicable state and federal laws and v) compliance with applicable regulatory mandates and obligations, including regulatory obligations related to serving load, interconnecting generation and providing transmission service.
- **Transmission Value Issue.** A Transmission Issue resulting from the opportunity or obligation to provide added economic value to Transmission Customers through specific expansions of the Transmission System, where added economic value is the difference between the financially quantifiable benefits associated with specific expansions to the Transmission System and the financially quantifiable costs of those expansions. A Transmission Value Issue may be incremental to the resolution of a Transmission Compliance Issue or may stand on its own.

2 Overview of Transmission Planning

2.1 MISO Transmission Planning Objectives

MISO regional transmission planning process has as its goal the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The planning process identifies solutions to reliability issues that arise from the expected dispatch of Network Resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects, and increased operating expenses from re-dispatching Network Resources or other operational actions.

At the start of 2006, the Transmission Provider Board adopted five planning principles to guide MISO regional plan:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs.
- Provide a transmission infrastructure that safeguards local and regional reliability.
- Support State and Federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand-side management).
- Create a mechanism to ensure that investment implementation occurs in a timely manner.
- Develop a Transmission System scenario model and make it available to State and Federal energy policy makers to provide context and information regarding potential policy choices.

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 into its planning process, and describes their functions in this Manual.

FERC Order No. 890 Planning Principles

(I) Coordination
(II) Openness
(III) Transparency
(IV) Information Exchange
(V) Comparability
(VI) Dispute Resolution
(VII) Regional Participation
(VIII) Economic Planning Studies
(IX) 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:

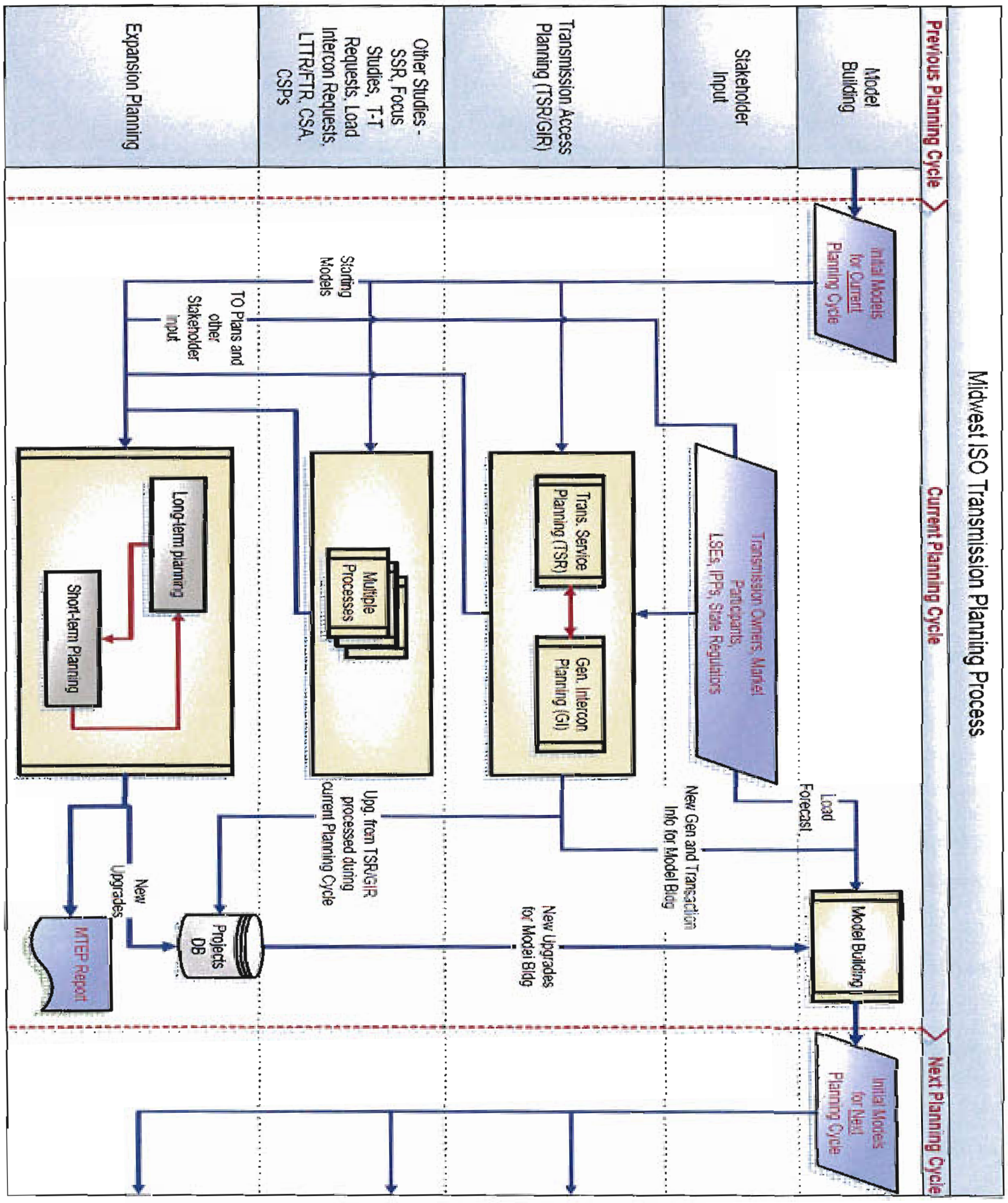
- Model Development
- Cyclical Baseline Reliability and Economic Planning
- Transmission Access Planning
  - Generator Interconnection Planning
  - Transmission Service Planning
- Coordinated Inter-regional Planning (with other RTOs/Regions)
- Non-cyclical Planning Needs
- System Support Resource (SSR)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

Each of these functions is 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 TSG and GIR processes occur on a continuous basis in response to customer requests for service. The Baseline planning function repeats on a regular cycle, with an MTEP report produced each 12 months. Each of these processes informs the other at the commencement of each functions cycle, as shown in Figure 2.2-1 below.

Fig 2.2-1: High-level Planning Process Flow Diagram



2.3 Project Appendices in the Projects Database

This section describes the requirements for a project to be categorized in either Appendix A, B, or C of the MTEP and the process by which projects progress through these Appendices.

MTEP Appendix C

Appendix C projects are projects which are proposed by Transmission Owners, Stakeholders, or MISO planning staff for which specific needs have not yet been established, but that are thought by sponsor to be a potentially beneficial expansion, and for which the sponsor has provided to MISO a description of the potential need or benefit. All newly proposed projects start as Appendix C projects in the MTEP planning process. These could also include transmission projects which are conceptual in nature and in the early stages of planning. Appendix C projects are not included in MTEP initial power-flow models used to perform baseline reliability studies since the needs or the effectiveness of these projects are yet to be verified. In order to advance to Appendix B, Appendix C projects must be matched as a potential solution to an identified reliability, policy or other need, or to an identified cost savings or other benefit.

MTEP Appendix B

Appendix B projects are projects that are demonstrated to be a potential solution to an identified reliability, policy or other need, or to an identified cost savings or other benefit. In the MTEP development process, an initial needs or potential benefit analysis is performed based on applicable criteria. Once a need or potential benefit is identified, potential solutions from Appendix C are tested for effectiveness in meeting the needs or providing the benefits. Appendix C projects with verified needs and effectiveness are then moved to Appendix B as potential needs to an expansion driver. It is possible that there could be several alternative Appendix B projects to address the same planning issue or need. Projects will remain in Appendix B until the evaluation process for selecting the preferred solution among alternatives is completed.

MTEP Appendix A

Appendix A projects are projects that have been justified to be the preferred solution to an identified reliability, policy or other need, or to achieve an identified cost savings or other benefit and that have been approved by the Transmission Provider Board. The project justification process includes consideration of a variety of factors including urgency of need and comparison from amongst alternatives of operating performance, initial investment costs, robustness of the solution, longevity of the solution provided, and performance against other economic metrics. Pending Appendix A projects are recommended for approval by the Transmission Provider Board. Once a project is approved by the Transmission Provider Board as an Appendix A project, the project is implemented in accordance with the Owners Agreement and the Tariff. Projects in Appendix A may be generated from the baseline planning process, or from the generator interconnection or Transmission Service request study processes. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff, and are categorized according to their cost sharing eligibility. See Section 2.4 of this BPM (MTEP Project Categories) for descriptions of the different categories of Appendix A projects. See Section 8.0 (Cost Allocation Process) for details on eligibility criteria and cost allocation methodologies.

The general process flow steps associated with MTEP projects from inception to approval is described below. A process flow chart for the same is shown in Fig 2.3-1 below.

(I) **Projects get into Appendix C as a result of one of the following**

- Developed by Transmission Owner as a potential solution to a local planning need and submitted to the MTEP planning process
- Developed by MISO planning staff in collaboration with Transmission Owners and other stakeholders during the planning process as a potential solution for a need or as a value based economic project
- Moved from Appendix B to Appendix C due to a previously identified need no longer being valid or the solution no longer being effective or efficient

(II) **Move Projects from Appendix C to Appendix B**

It is important to understand that many proposed solutions represent projects that 1) are low cost, 2) are not cost shared, 3) address a single local Transmission Issue such as the projected violation of a single NERC TPL standard and 4) are clearly the preferred solution for the specific Transmission Issue being addressed. Under these types of scenarios, engineering judgment will be exercised by MISO to determine if it is necessary to employ comprehensive effectiveness testing as described below.

- MISO planning staff will work with Transmission Owners and other stakeholders to perform long-term planning as described in Section 4.4 of this document to develop alternative solutions to one or more Transmission Issues where Transmission Issues include Transmission Compliance Issues and Transmission Value Issues.
- An effectiveness test will be used to verify whether a solution, which can be one or more proposed projects, effectively resolves Transmission Compliance Issues and/or address Transmission Value Issues. MISO planning staff will work with Transmission Owners and other stakeholders to perform the effectiveness testing.
- In order to be considered effective, a proposed solution must i) effectively resolve one or more Transmission Compliance Issues; or ii) address one or more Transmission Value Issues within the long-term planning horizon.
- Effectiveness testing for Transmission Compliance Issues will involve testing a proposed solution to ensure it resolves one or more Transmission Compliance Issues.

  Effectiveness testing for Transmission Compliance Issues will involve testing proposed transmission solutions against generation and load models that comply with state and federal laws, regulatory obligations and regulatory mandates to ensure compliance with applicable NERC, Regional Entity, and, when appropriate, local and Transmission Owner reliability standards. Effectiveness testing against reliability standards for the purpose of determining Appendix B inclusion will include thermal and voltage limit analyses only and may include stability analysis where it is determined necessary by MISO.
- Effectiveness testing for Transmission Value Issues will involve modeling a proposed transmission solution to determine if the present value of: i) annual production costs savings; ii) resource capacity cost savings; and, iii) other financially quantifiable benefits related to the provision of Transmission Service is greater than the present

value of the annual revenue requirements of the proposed solution over the first 20 years of the solution's life.

- Stakeholders will review results of effectiveness testing and provide input.
- MISO staff will perform additional analyses and modify proposed solutions as needed based on stakeholder feedback.
- A proposed project will be included in Appendix B of the MTEP if the project is shown to effectively resolve one or more Transmission Compliance Issues or addresses one or more Transmission Value Issues when evaluated over a period of 20 years. For proposed projects that address both Transmission Compliance Issues and Transmission Value Issues, all that is necessary for Appendix B inclusion is to demonstrate the ability to address one or more Transmission Compliance Issues, thus detailed value assessment of such a project is not required until consideration for Appendix A inclusion.
- Potential projects driven by specific Generation Interconnection Requests or Transmission Service Requests that are not required to be constructed within the short-term planning horizon will also be included in Appendix B.

(III) **Review Process for Inclusion in Appendix A**

- MISO planning staff will work with Transmission Owners and other stakeholders to perform short-term planning as described in Section 4.3 of this document to develop solutions to one or more short-term Transmission Issues where short-term Transmission Issues include Transmission Compliance Issues and Transmission Value Issues within the short-term planning horizon. There is no requirement that a project must have an in-service date within the short-term planning horizon to be eligible for inclusion in Appendix A if other considerations (e.g., project lead times, etc.) warrant inclusion of the project in Appendix A in a given MTEP cycle.
- In developing solutions for short-term Transmission Issues, MISO planning staff will work with Transmission Owners and other stakeholders (via SPMs, the PS and the PAC) to identify projects from Appendix B and, when necessary or prudent, other potential sources that will assist in addressing one or more short-term Transmission Issues.
- All projects contained within Appendix B will be considered for inclusion in Appendix A.

- MISO planning staff review cost estimates of identified potential projects with Transmission Owners and other stakeholders through the SPM process.
- It is expected that most Transmission Issues being addressed by short-term planning will be decoupled. A Decoupled Transmission Issue is a Transmission Issue that does not share the same root cause as any other Transmission Issue and does not have a solution that is common to any other Transmission Issue. For this reason, solutions to Decoupled Transmission Issues are Non-dependent Transmission Projects, where a Non-dependent Transmission Project is any transmission project that can be selected to address a specific Transmission Issue without regard to how other Transmission Issues are being resolved.
- In accordance with Appendix B of the ISO Agreement, a Transmission Owner shall have the right to require the inclusion of any specific transmission project directly associated with the Transmission Owner's transmission system into Appendix A of a specific MTEP as long as such project does not result in system performance that is inconsistent with applicable reliability criteria. Such projects will be considered Non-dependent Transmission Projects regardless of whether or not the Transmission Issues being addressed are Decoupled Transmission Issues. Such a project will not be eligible for cost sharing as a Baseline Reliability Project, Market Efficiency Projector Multi Value Project if the project would not otherwise be approved for construction in the MTEP.
- While it is expected that most Transmission Issues will be decoupled, it is also expected that a number of Transmission Issues will be highly coupled. That is, selection of the best project to resolve a specific issue is highly dependent on the solutions selected for other Transmission Issues being addressed by the Short-term Transmission Plan. This type of project will be referred to as a Dependent Transmission Project.
- In order to evaluate portfolios of Dependent Transmission Projects, MISO planning staff in collaboration with Transmission Owners and other stakeholders will determine if alternative Short-term Transmission Plans should be considered, and if so, will develop alternative Short-term Transmission Plans where each alternative Short-term Transmission Plan represents a specific set of proposed projects for Appendix A. Each alternative Short-term Transmission Plan must resolve all Transmission Compliance Issues in the short-term planning horizon, must allow for Transmission Compliance Issues to be resolved in the long-term planning horizon

when project lead times are an issue and should address Transmission Value Issues that commence in the short-term planning horizon, where Transmission Value Issues only exist when there is a solution with costs that are lower than the financially quantifiable benefits produced by the solution. Each alternative Short-term Transmission Plan will contain all of the Non-dependent Transmission Projects, since inclusion of Non-dependent Transmission Projects in Appendix A does not require evaluation of the overall Short-term Transmission Plan. However, alternative portfolios of Dependent Transmission Projects will be assigned to each alternative Short-term Transmission Plan to accurately determine which set of Dependent Transmission Projects should be incorporated into the Short-term Transmission Plan and ultimately transferred to Appendix A to address the Coupled Transmission Issues.

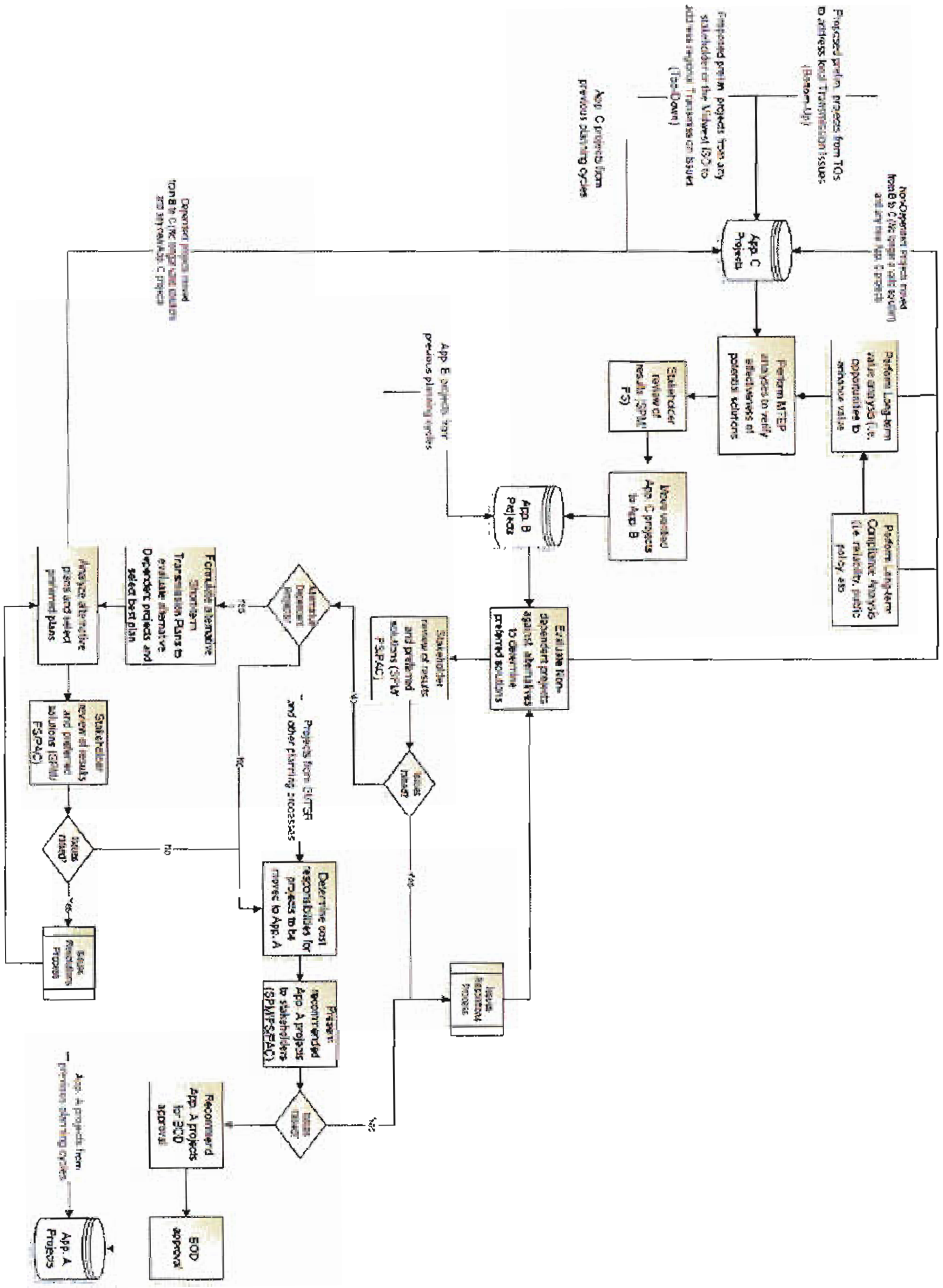
- MISO planning staff in collaboration with Transmission Owners and other stakeholders will evaluate the alternative Short-term Transmission Plans to ensure they resolve all Transmission Compliance Issues. MISO planning staff will determine and review with Transmission Owners and other stakeholders the Total Plan Value and Total Plan Benefit-to-cost Ratio associated with each alternative Short-term Transmission Plan where Total Plan Value and Total Plan Benefit-to-cost Ratios are described in Section 4.3.11 of this document.
- Any alternative Short-term Transmission Plan that meets one of the following criteria will be analyzed further whereas all other alternative Short-term Transmission Plans will be discarded.
    i. The alternative Short-term Transmission Plan providing the highest Total Value as described in Section 4.3.11.1 of this document.
    ii. The alternative Short-term Transmission Plan providing the highest Total Plan Benefit-to-cost Ratio as described in Section 4.3.11.2 of this document.
    iii. Any alternative Short-term Transmission Plan with a Total Plan Value greater than or equal to 75% of the highest Total Plan Value of all alternative Short-term Transmission Plans and a Total Plan Benefit-to-cost Ratio greater than or equal to 75% of the highest Total Plan Benefit-to-cost Ratio of all alternative Short-term Transmission Plans.

- MISO planning staff in collaboration with Transmission Owners and other stakeholders will evaluate the alternative Short-term Transmission Plans that qualify for further analysis (i.e., the alternative Short-term Transmission Plans meeting one or more of the criteria specified in the proceeding bullet) based on the factors listed in Section 4.3.11.4 of this BPM to determine the preferred Short-term Transmission Plan.
- MISO will include a section in the MTEP report explaining how the factors in the preceding bullet were applied by MISO, Transmission Owners and other stakeholders to determine the preferred alternative Short-term Transmission Plan.
- All projects included in the alternative Short-term Transmission Plan selected as the preferred Short-term Transmission Plan will be moved to Appendix A.

(IV) **Additional Notes Related to Appendix A Inclusion**

- The Issues Resolution process will be used to address any issues with planning assumptions and criteria used.
- Appendix A will also include any projects initiated and developed though other planning processes for Interconnection Requests and Transmission Service requests.
- MISO planning staff will determine cost responsibilities for the projects to be recommended as Appendix A.
- MISO planning staff will present the recommended Appendix A projects to stakeholders.
- The Issues Resolution process will be used to address any cost allocation issues.
- MISO planning staff recommends new Appendix A projects for approval by the Transmission Provider Board and for implementation by Transmission Owners.

Fig 2.3-1: MTEP Projects C to B to A process



2.4 MTEP Appendix A Project Categories for Cost Allocation Purposes

The MTEP will identify the following types of Appendix A expansion projects for inclusion in the MTEP.

2.4.1.1 Baseline Reliability Projects (BRP)

Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable to the Transmission Provider. BRPs include projects that are needed to maintain reliability while accommodating the ongoing needs of existing Market Participants and Transmission Customers. BRPs may consist of a number of individual facilities that in the judgment of the Transmission Provider constitute a single project for cost allocation purposes. The Transmission Provider will collaborate with Transmission Owners and with other transmission providers to develop appropriate planning models that reflect expected system conditions for the planning horizon. The planning models will reflect the projected load growth of existing network customers and other transmission service and interconnection commitments, and will include any transmission projects identified in Service Agreements or interconnection agreements that are entered into in association with requests for transmission delivery service or transmission interconnection service, as determined in Facilities Studies associated with such requests. The Transmission Provider will test the MTEP for adequacy and security based on commonly applicable national Electric Reliability Organization ("ERO") standards, and under likely and possible dispatch patterns of actual and projected Generation Resources within the Transmission System and of external resources, and will produce an efficient expansion plan that includes all BRPs determined by the Transmission Provider to be necessary through the planning horizon of the MTEP. The Transmission Provider will obtain the approval of the Transmission Provider Board, as set forth in Section VI, for each MTEP published. BRPs need to meet the cost thresholds specified in Attachment FF in order to be eligible for cost sharing.

2.4.1.2 New Transmission Access Projects (TAP)

New Transmission Access Projects are derived from the Facilities Studies as Generator Interconnection Projects and Transmission Delivery Service Projects, which are described below. Please see Section 5.0 (TSR) and Section 6.0 (GI) of this manual for process details on TAPs.

I) Generation Interconnection Projects (GIP)

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. The Interconnection Customer is responsible for 100 percent of the costs of Network Upgrades rated below 345 kV and 90 percent of the costs of Network Upgrades rated at 345 kV and above (with the remaining 10 percent being recovered on a system-wide basis. For interconnection customers interconnecting to American Transmission Company (ATC LLC) transmission systems and meeting certain eligibility requirements, 50% of the Network Upgrade cost is allocated entirely to ATC LLC pricing zone and the remaining 50% is allocated to affected pricing zones based on sub-regional and/or postage-stamp allocation rules described under Attachment FF. A similar treatment is applicable to interconnection customers interconnecting to ITC/ITCM/METC transmission systems and meeting certain eligibility requirements.

II) Transmission Delivery Service Projects (TDSP)

Transmission Delivery Service Projects are Network Upgrades driven by Transmission Service Request (TSR) study procedures and agreements. These upgrades are needed to respond to requests for new Point-To-Point Transmission Service, or requests under Module B of the Tariff for Network Service or a new designation of a Network Resource. Cost of these upgrades are either directly assigned or rolled-in as per Attachment N of the Tariff.

2.4.1.3 Market Efficiency Projects (MEP)

Market Efficiency Projects are Network Upgrades: (i) that are proposed by the Transmission Provider, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities; (ii) that are found to be eligible for inclusion in the MTEP or are approved pursuant to Appendix B, Section VII of the ISO Agreement after June 16, 2005, applying the factors set forth in Section I.A. of Attachment FF; (iii) that have a Project Cost of $5 million or more; (iv) that involve facilities with voltages of 345 kV or higher[1] ; and that may include any lower voltage facilities of 100kV or above that collectively constitute less than fifty percent (50%) of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio threshold for the project as established in Section II.B.1.e, or that otherwise are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project; (v) that are not determined to be MVPs and (vi) that are found to have regional benefits under the criteria set forth in Section II.B.1. of Attachment FF.

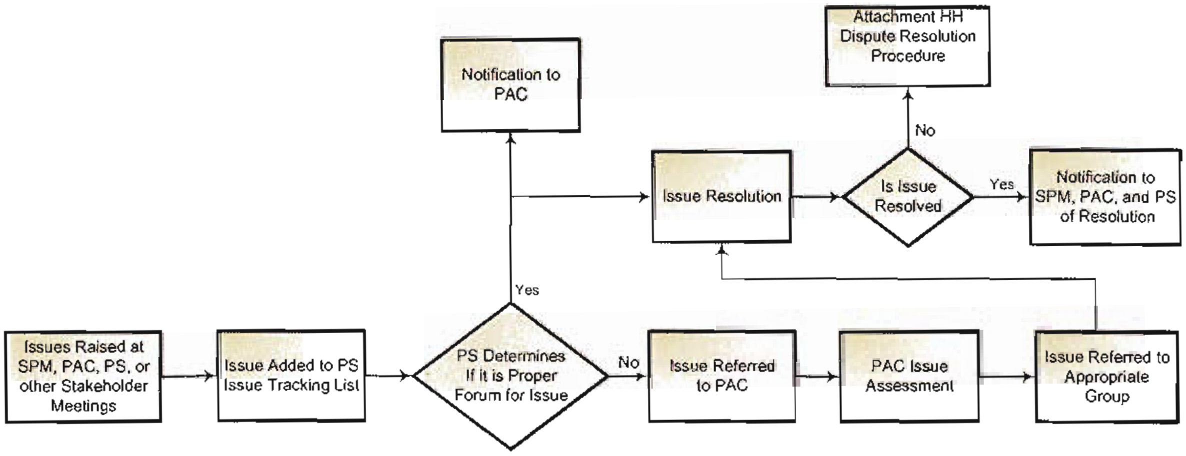
2.4.1.4 Other Projects

Other projects are defined as projects that are not covered by the project categories described above, but are included in an MTEP report. These could include, (i) Transmission Owner initiated reliability projects driven by local reliability planning criteria, (ii) Transmission Owner initiated economic projects that do not meet Attachment FF economic inclusion criteria, and (iii)Transmission Owner initiated projects that may prove to be MEP or cost shared BRP but for which MISO has not yet determined the cost sharing of, but that the Transmission Owner requires (for state regulatory proceedings or other cost recovery reasons under the Tariff) be included in the MTEP. The cost responsibility for these "Other Projects" is per the ISO Agreement through Attachment O recovery until such time as MISO were to complete analyses sufficient to reclassify the project(s) as an MEP or BRP with other appropriate cost sharing methodologies described herein.

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

[1] Transformer voltage is defined by the voltage of the low-side of the transformer for those purposes.

Fig. 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 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:

a. Model development
b. Testing models against reliability and economic planning criteria
c. Collaborative development of possible solutions to identified issues
d. Selection of preferred solution
e. Determination of funding and cost responsibility
f. 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 (LSEs), Generation Owners, Transmission Customers, Transmission Owners, and neighbouring 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 SPMs, PS, and PAC 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 Owners 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 owners 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 Owners

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 Owners 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 Owners will adhere to any applicable state or local regulatory planning processes. Proposed plans developed by the Transmission Owners 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 Owners 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 Owners 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 Owners are required to provide representatives that can support these discussions and respond to stakeholder questions about project details.

Transmission Owners are responsible for supporting and participating in the development of MISO and Inter-RTO planning models. The Transmission Owners 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 Owners 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 Owners 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 Owners 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 used by MISO and Transmission Owners 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 Owners 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 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 [MISO is presently considering which of these two reporting requirements is most appropriate for providing LSE load forecast information]. 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 be 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 Owners 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.

3 Model Development

3.1 Introduction

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 manual.

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 below shows a general overview of the Planning Model Building Development process through MOD. The key process steps are explained below and Table 3.2-1 below identifies the planning model development timeline, key milestones, and responsibilities.

3.2.1.1 Initiate Base Model Development for the Next Planning Cycle

MISO planning staff in consultation with PS/PAC 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 Owners 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 Owners submit PSS/E IDEVS ("MOD project files") to MOD for new Appendix C "candidate" projects. Also, Transmission Owners review Appendix A, Appendix B, and Appendix C 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 Owners also make any changes or corrections to equipment ratings though the MOD data submittal process.

MOD load data is updated for the selected planning study years and seasons based on the load forecast data collected and/or projected by the Transmission Owners at the substation level. Transmission Owners update these load data and profiles though MOD. MISO also collects load forecast data from LSEs/Network Customers and the MOD load forecast information based on Transmission Owner input is compared with load forecast data collected from LSEs/Network Customers at the beginning of the planning cycle.

New generator information coming out of the Generator Interconnection process is also used to update the MOD. MISO planning staff uses the available Generator Interconnection study information to update the MOD for new units. Any unit retirement information available through the SSR study process is also used to update the MOD.

MISO planning staff also makes any 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/Models ftp site: <https://www.midwestiso.org/Planning/Models/Pages/Models.aspx>]. The schedule for review and feedback is posted on the ftp site along with the models and typically has the timelines shown in Table 3.2-1 below.

3.2.1.4 Develop Base Models for Planning Studies

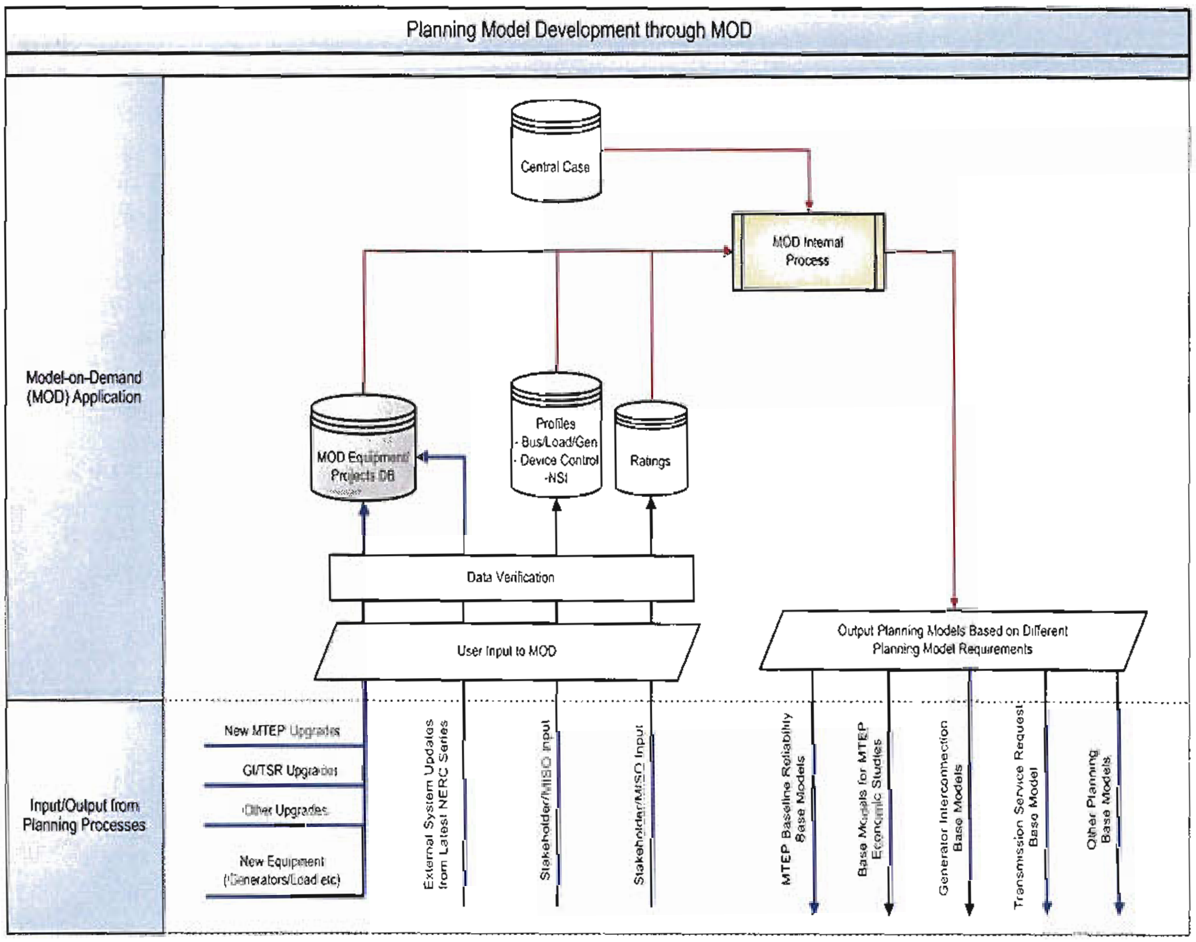
Any additional model updates and corrections needed are submitted through MOD by the appropriate data submitters described above. MISO planning staff then posts the Base Models for different planning functions on the ftp site.

Table 3.2-1: Model Development Timeline, Key Milestones, and Responsibilities (Occurs between August and January 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 Appendix C projects	Transmission Owners
Review Appendix A, and Appendix B projects in MOD (processed during previous planning cycle) and submit corrections and modifications as necessary	Transmission Owners
Submit equipment rating updates and other model corrections	Transmission Owners
Submit Transmission Owner collected/projected load forecast data to MOD on a substation basis	Transmission Owners

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 Owners
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 Owners
Post revised base models on the ftp site	MISO planning staff

Fig 3.2-1: Planning Model Development - MOD Input/Output



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 Study Horizon

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

- Five year out summer peak case
- Five year out summer 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.

3.2.1.6 Model Requirements

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

3.2.1.7 Model Review

MISO planning staff will create the initial MTEP reliability planning models using MOD and post the starting models on the MTEP ftp site (ftp://mtep.misoenergy.org/) for stakeholder review. Access to MTEP models requires executing the relevant non-disclosure agreements (NDA) and following the instructions posted on the MISO Transmission Expansion Planning page, <https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx>, in order to have access to the MTEP ftp site. Any needed corrections or adjustments will be made before using the MTEP planning models for reliability simulations. 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.

3.2.2 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.

3.2.2.1 Study Horizon

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

- Five year out summer peak case
- Ten year out summer peak case
- Fifteen year out summer peak case

3.2.2.2 Model Requirements

Transmission topology data for the economic models are based on the power-flow base models applicable to the chosen economic study year. The load and generation information source is as described in Section 4.4.3. See section 4.4.3 *infra* for additional information on data Sources and assumptions used for economic studies.

3.2.2.3 Model Review

MISO planning staff will create the initial MTEP economic planning models using MOD and post the starting models on the MTEP ftp site (ftp://mtep.misoenergy.org/) for stakeholder review. Changes identified through the stakeholder review will be made prior to using the power-flow 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.

3.2.3 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.

3.2.4 Base Models for Transmission Service Request Studies

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

3.2.5 Base Models for Other Non-cyclical Planning Studies

Section 7.0 describes the specific model requirement for other non-cyclical planning studies. Unless otherwise specified under Section 7, 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. Transmission Owner provided load forecast is compared with the load forecast data collected by MISO from LSEs. Coincident loads of each 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 User manual 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. 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, appropriate 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.

3.3.4 Transactions/Interchanges

The interchanges modeled are derived from the transactions modeled in the latest NERC series models and as updated by 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 models in general reflect the bulk transmission system as typically modeled in NERC series models. Any lower-voltage details may also be reflected as needed to 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 Continuous rating or applicable rating for system intact conditions will be populated into NORM rating field of MOD. Emergency rating or applicable rating for contingent conditions will be populated in STE rating field. For purposes of planning model building the STE field in MOD stands for Emergency rating or applicable rating for contingent conditions. When producing power flow models from MOD, Rate A will be populated with NORM rating from MOD and Rate B will be populated with STE (emergency) rating from MOD for appropriate season.

4 Baseline Planning

Baseline planning establishes a "baseline" of transmission expansions that are needed to meet ongoing commitments and future needs both reliably and efficiently. As such, baseline planning encompasses a number of sub-processes that link to each other but that have their own associated procedures, schedules, and stakeholder interactions, which are needed to address reliability as well as economic criteria over the short and long-term planning horizons.

Figure 4.2-2 below depicts the steps involved in the overall baseline planning process for both short and long-term planning horizons.

The present MTEP regional planning processes involve a top-down long-term "value-based" process that has extended the planning horizon to 20 years and incorporates the development of future generation scenarios and transmission options that can efficiently and reliably deliver such generation. Part of the long-term analysis involves determining when expansions that have long-term value should be built. Until projects developed through the long-term value-based planning efforts are constructed, the more traditional bottom-up reliability focused planning processes will continue to develop projects needed in the shorter-term to maintain system reliability. The short-term planning process tends to be focused on ensuring that peak demand can be met reliably and usually identifies projects of a more local nature as opposed to larger regional solutions that may provide enhanced value but can only be constructed over a longer time period. As this long-term process evolves and prudent expansions are committed to, they will likely displace alternative expansion developed via the short-term planning processes. The Short-term processes begin with a roll-up of issues and potential solutions from the local planning processes of the Transmission Owners, and integrate these into the regional planning process to ensure that the most efficient projects are developed and that aggregate customer needs are met. The short and long term planning processes are both resource intensive efforts that involve extensive stakeholder interaction and are necessarily pursued in parallel, with the results of each process informing the other as each cycle progresses. Figure 4.2-2 demonstrates how the local planning processes, the short-term regional processes, and the long-term-regional processes inter-relate.

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 Sub-regional Planning Meetings

Sub-regional 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 three planning regions established under Attachment FF (West, Central, and East). The SPMs will occur at the times and for the purposes listed below associated primarily with the short-term planning process described in Section 4.3.

Table 4.1-1: 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 and proposed projects reported by Transmission Owners	January	West, Central, East (locations to be announced)

1. Review system performance issue identified in initial phase analysis. 2. Discuss possible alternative solutions to issues	March/April	West, Central, East (locations to be announced)

1. Review results of alternative analyses 2. Comment on proposed preferred solutions	June/July	West, Central, East (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 below associated primarily with the short-term planning process described in Section 4.3.

Table 4.1-2: PS Meetings Schedule

Purpose	Date	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 (Reference Committee calendar for dates)	Carmel or St. Paul (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 (Reference Committee calendar for dates)	Carmel or St. Paul (location to be announced)
1. Review MTEP analysis results 2. Other regular agenda items as developed by MISO planning staff or participants	June (Reference Committee calendar for dates)	Carmel or St. Paul (location to be announced)
1. Comment on proposed preferred solutions 2. Review preliminary Cost	August (Reference Committee calendar for dates)	Carmel or St. Paul (location to be announced)

Allocations 3. Other regular agenda items as developed by MISO planning staff or participants		
1. Comment on MTEP Report Draft 3. Other regular agenda items as developed by MISO planning staff or participants	September (Reference Committee calendar for dates)	Carmel or St. Paul (location to be announced)

1. Input on completed MTEP process 2. Other regular agenda items as developed by MISO planning staff or participants	October (Reference Committee calendar for dates)	Carmel or St. Paul (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 (Reference Committee calendar for dates)	Carmel or St. Paul (location to be announced)

4.1.3 Planning Advisory Committee

The Planning Advisory Committee (PAC) is established under the Transmission Owners 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 Owners
- 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

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 to 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.

4.2 Pre-planning Steps Common to Short-Term and Long-term Planning

Each MTEP regional planning cycle commences with the assembling of initial information from stakeholders and Transmission Owners, 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 Owners 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 Owners 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 Owners 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 Owners at the front end of the annual planning cycle through a project reporting procedure. The local plans of Transmission Owners 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 forms:

(1) To MOD for model level data (idevs, etc.)
(2) 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 Owners 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 Owners. The regional planning process evaluates, with stakeholder input throughout the cycle, the local plans of these Transmission Owners, as one input into the development of the regional plan.

4.2.3 Project Reporting Guidelines

Members who are Transmission Owners 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).
- 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 Owners 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 Owners agreement. Other

Transmission Owners 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 “Out-of-Cycle Project Review” procedure described elsewhere in this BPM.

Project data is presently submitted to the Project Database using the database reporting tool that consists of a pre-formatted Excel workbook with fields to accommodate the necessary entries and reporting requirements. The Excel workbook includes tables defining Project, “Facility”, and “Needs” entries. The Project and Facility table field definitions are presented in Appendix K of this Manual. Modeling data associated with these projects should also be submitted to the MOD 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 Owners through the MISO planning process and into applicable reports is shown in Figure 4.2-1 below.

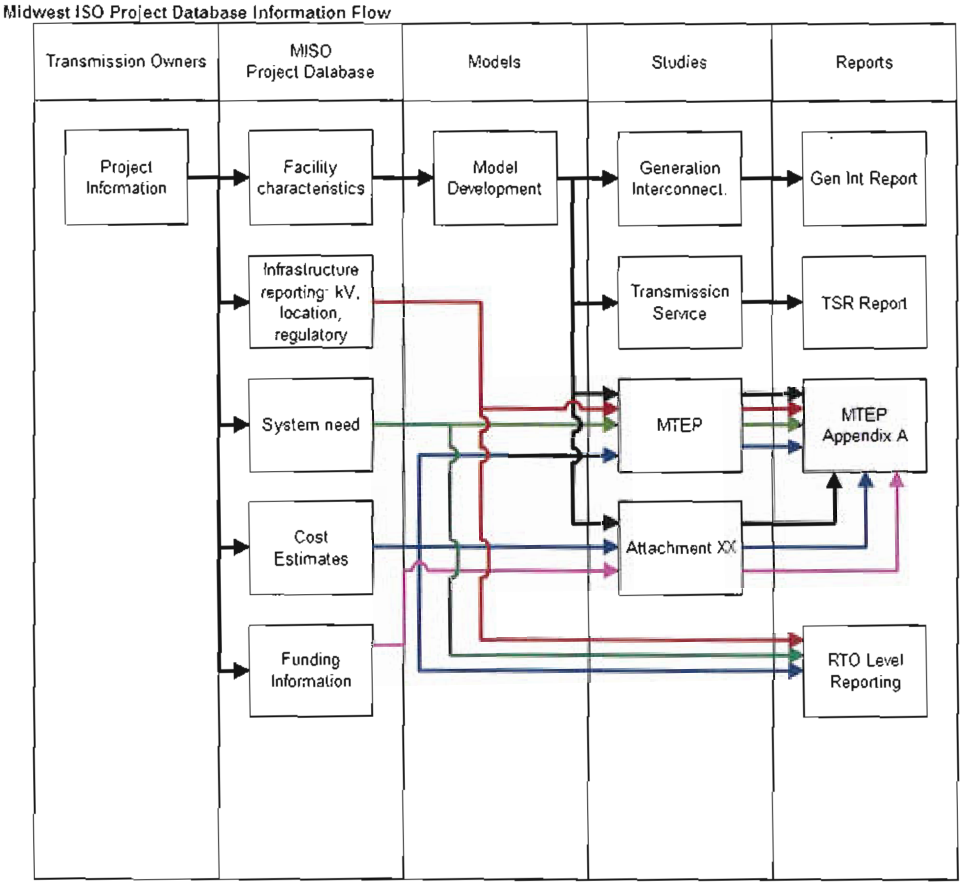


Figure 4.2-1 MISO Projects Database Information Flow

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 PS 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.

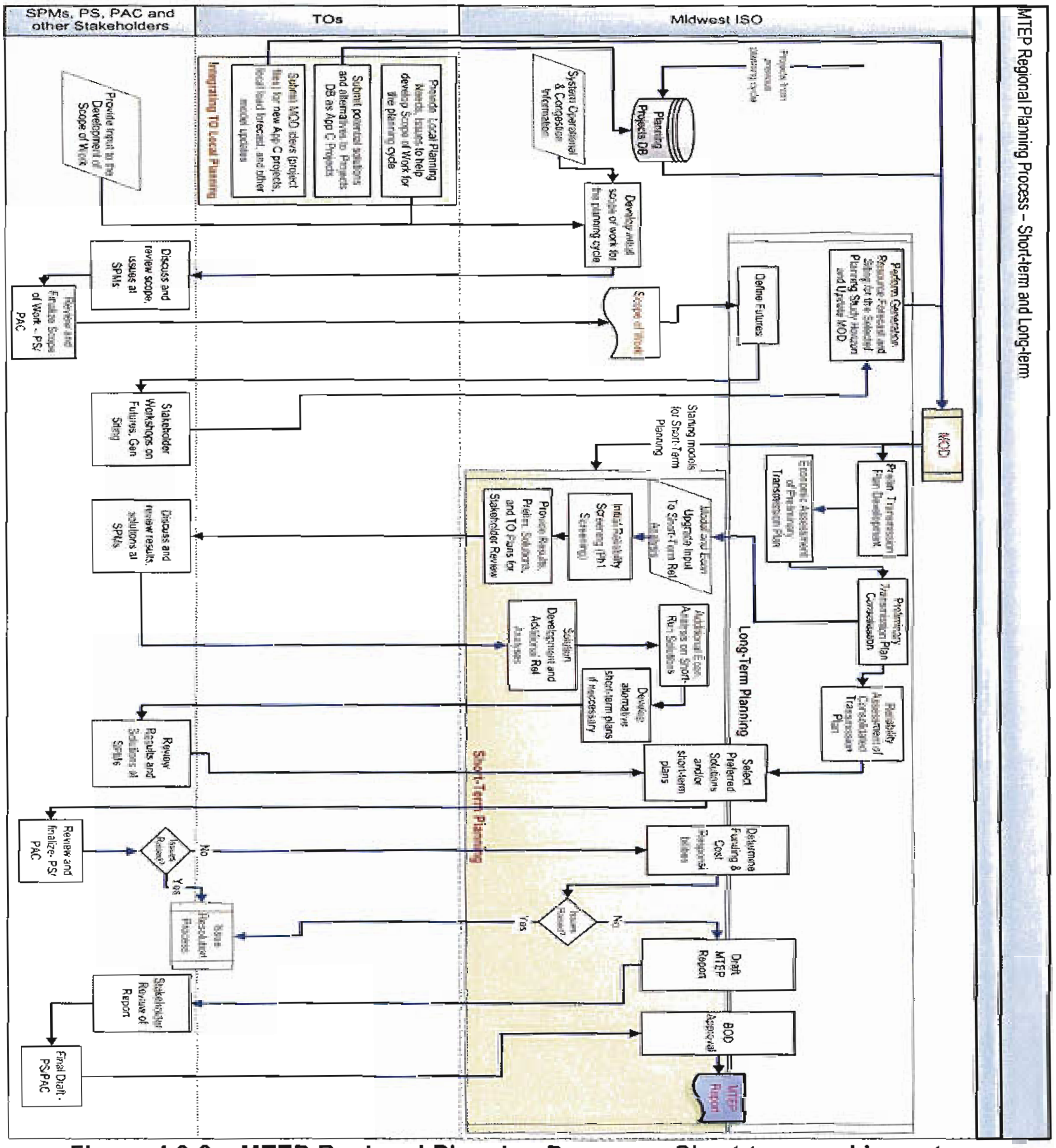


Figure 4.2-2 – MTEP Regional Planning Process – Short-term and Long-term

4.3 Short-Term Planning

Short-term planning addresses identification of Transmission Issues and development of firm solutions in the time frame of 1 to 10 years, with particular focus on the next 5 years. Screening reliability analyses are performed in the 6-10 year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards. For example, it is possible that the best solution to an issue identified in year 8 could be a transmission line that may reasonably have a 5 year lead-time to develop and commission. Such a project would need to begin construction in the next three years and should begin to be budgeted for.

Short-term Transmission Plans represent all of the projects that must be considered for Appendix A approval in the current planning cycle in order to address Transmission Issues when considering approval and construction lead-times. Short-term Transmission Plans may arise from newly proposed projects in the current planning cycle or from projects in Appendix C or B from prior planning cycles.

4.3.1 Steps in the Short-term Planning Process

Key Milestone points in the short-term planning process are:

- Assemble input information for planning cycle
- Develop scope of work for the current planning cycle
- Model development
- Testing models against planning criteria
- Development of possible solutions to identified issues
- Development of one or more alternative Short-term Transmission Plans
- Selection of the preferred Short-term Transmission Plan if alternative plans have been developed
- Determination of funding and cost responsibility
- Monitoring progress on solution implementation

4.3.2 Short-term Planning Analysis Methodology

Short-term Planning analysis provides an independent assessment of the ability of the currently planned MISO Transmission System to resolve all Transmission Compliance Issues within the short-term planning horizon including but not necessarily limited to the following:

- Compliance with applicable NERC TPL and Region Entity Standards
- Compliance with applicable State and Federal Laws
- Compliance with applicable regulatory mandates and obligations
- Compliance with applicable local standards and requirements
- Compliance with applicable Transmission Owner standards and criteria

This is accomplished through a series of evaluations of the Transmission System in the short-term planning horizon with approved and expected Transmission System upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to resolve Transmission Compliance Issues. Approved upgrades are in Appendix A and expected upgrades are projects expected to move to Appendix A in the current planning cycle. This assessment is accomplished through steady-state power flow, dynamic stability, small-signal, load deliverability, and voltage stability analysis of the Transmission System performed by MISO planning staff and reviewed in an open Stakeholder process.

4.3.3 Short-term Planning Analysis – Process Overview

Figure 4.3-1 below shows the process flow diagram for the short-term planning analysis. The initial phase of the analysis documents the system issues driving projects in the MISO MTEP Projects database. This initial analysis identifies Transmission Compliance Issues and Transmission Value Issues driving the projects. This is followed by a solution development phase in collaboration with the stakeholders. To the extent transmission compliance issues directly resulting from a new solution require turning down Provisional Interconnection Agreement (PIA) units and/or Energy Resources (ERs) in the planning horizon studies, information on these generating stations along with their participation (where greater than 10%) to associated constraints will be presented at the Sub Regional Planning Meetings. These solutions along with projects driven by other planning needs and functions will be analyzed to determine their effectiveness in resolving Transmission Compliance Issues and/or Transmission Value Issues within the short-term planning horizon.

The critical analyses are repeated to confirm that the identified new solutions when incorporated into the overall system expansion plan, resolve the Transmission Compliance Issues. The projects in the current transmission plan, which are the result of the transmission studies, are listed in Appendix A (projects approved by the Transmission Provider Board as the Short-term Transmission Plan) and Appendix B (projects addressing issues beyond the short-term planning horizon which require additional analysis and review before being submitted to the Transmission Provider Board for approval) and projects flagged to move to Appendix A or B in the current planning cycle. The primary inputs and assumptions for the short-term planning analysis are:

- The Transmission System condition to be modeled and analyzed with associated load, generation and base interchange values;
- The contingencies and system events to be analyzed;
- The facilities monitored with respect to the planning criteria; and
- The current transmission expansion plans from the planning process.

Planning criteria, models, and contingencies are discussed in the following sections.

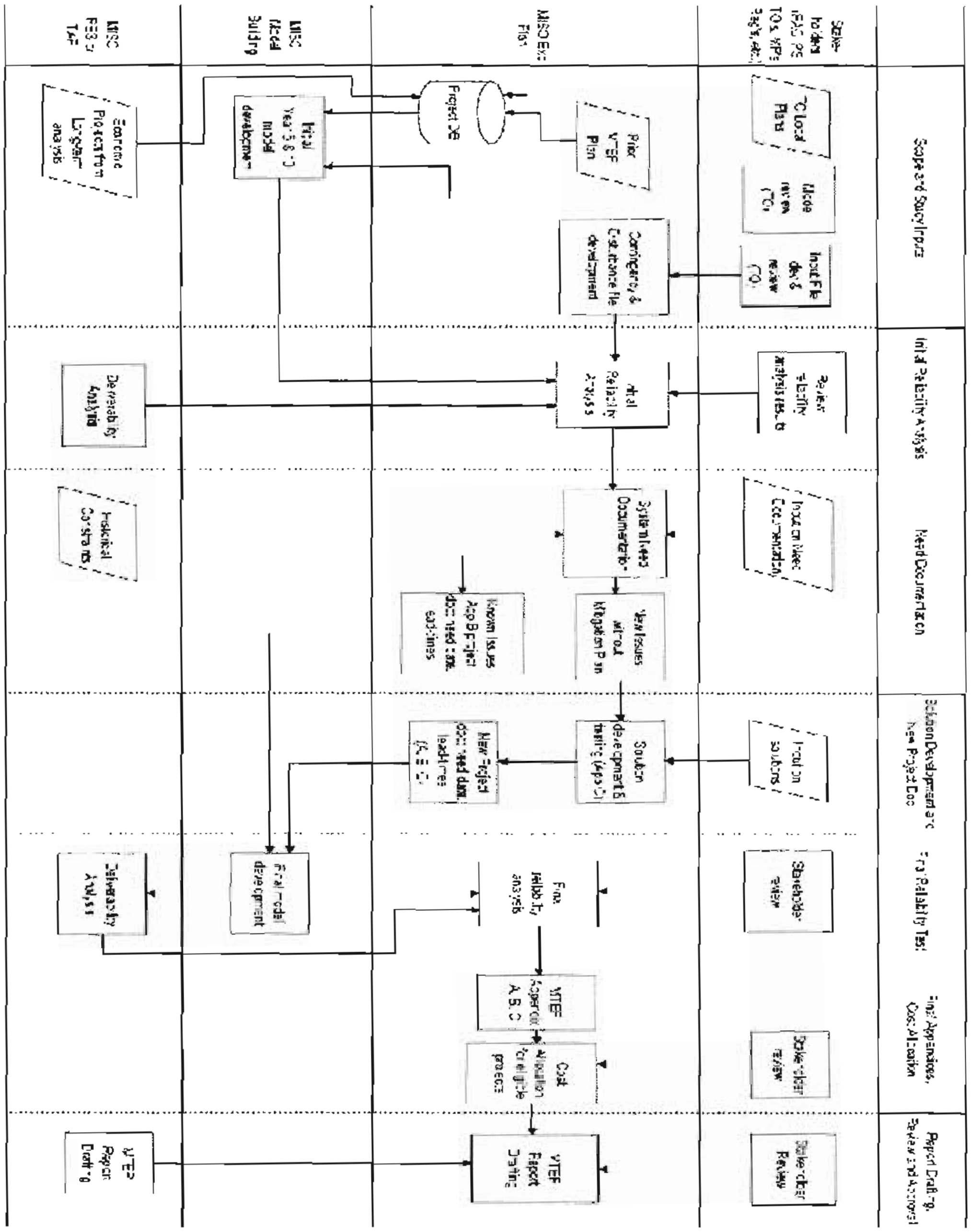


Figure 4.3-1 – Short-term Transmission Planning Methodology – Process Flow Diagram

4.3.4 Review of Market Participant Funded Projects

Process for evaluation of Market Participant funded projects is described in this section. Pursuant to Section III.A.2 of Attachment FF, Market Participant Funded Projects are defined as network upgrades fully funded by one or more market participants but owned and operated by incumbent Transmission Owners. 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 Owners.
- 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).

4.3.4.1 Process Steps

1. All such network upgrades shall be required to be submitted by Market Participants by September 15th for approval and subsequent inclusion in the MTEP in December of the following year. Exceptions to this rule shall only 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 Owners.
2. As with other projects, MISO shall post these network upgrades within five business days of receipt and communicate to applicable Transmission Owners.
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 Owners shall propose alternative transmission upgrades for market participant funding. These transmission upgrades may be upgrades to the existing system or new facilities.

4. Market Participant shall enter into a Study Services Agreement with the applicable Transmission Owners by December 31st. Agreements shall be consistent with Attachment X where all planning, engineering and other study costs associated with the MP request shall be borne by the Market Participant.
    a. To the extent multiple Market Participants propose to fund the same network upgrade, MISO will facilitate joint funding negotiations with applicable Transmission Owners. However, after commencement of studies, in such circumstances, no further amendments shall be made to the agreed upon services agreement. Negotiations of cost of study services between multiple Market Participants may happen but is outside of MISO study process.
5. MISO will present proposed network upgrades at its 1st SPM.
6. MISO in collaboration with applicable Transmission Owners shall conduct an engineering analysis which would include:
    a. Detailed engineering study of appropriate network upgrade needed to mitigate applicable constraint/s and associated estimate costs.
    b. 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 MISO 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.
7. MISO will communicate necessary upgrades and cost to the Market Participant and present study findings at 2nd SPM typically held in March.
8. Market Participants shall execute Facility Construction Agreement (FCA) with applicable Transmission Owners by end of September, or request that it be filed unexecuted at FERC by that time. MISO will also provide an update at the 3rd SPM typically held in June.
9. MISO will include the network upgrades in its current MTEP once FCAs are in place.
10. MISO will evaluate eligible Financial Transmission Rights (FTR) associated with the final network upgrades in accordance with the MISO tariff.

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

4.3.5 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owners Agreement, the MISO Transmission System is to be planned to meet local, regional and NERC planning standards. The short-term planning analysis performed by the MISO planning staff tests the performance of the system against the NERC Standards. Compliance with local requirements is assigned to the Transmission Owners, where those standards exceed NERC standards. The specific branch loading and bus voltage thresholds of a member's criteria (local flagging criteria) are applied to accurately reflect the different system design standards of our members.

All system elements that constitute the Transmission System of MISO planning regions as well as tie lines to neighboring systems are monitored. Some non-MISO member systems are monitored if they are within the MISO Reliability Area. System Intact conditions will be monitored against Normal continuous applicable rating. Contingent conditions will be monitored against Emergency or contingent applicable rating. For contingent events which do not allow for system adjustments, if contingent loading is above applicable rating, a mitigation plan must be developed.

4.3.6 Baseline Models - Data Sources and Assumptions

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.

4.3.6.1 Topology

The system topology in the short-term planning models will reflect the expected system condition for the planning horizon. This will include future transmission projects within the MISO Transmission System that are in i) Appendix A, ii) recommended to move to Appendix A in the current planning cycle or iii) are currently in Appendix B or recommended to move to Appendix B and are flagged in Appendix B as necessary to resolve Transmission Compliance Issues beyond the short-term planning horizon. The following general criteria will be used to model future transmission projects:

- Projects with Expected In Service Date before the short-term planning study horizon year (before July 1 for summer peak cases);
- Projects with Regulatory Approvals;

- Projects with system needs documented by MISO (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 Interconnection Agreements;
- 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.

4.3.6.2 Generation, Load, and Interchanges

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 4.4 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 7.2). In any event, sufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the short-term planning horizon. 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.

A Security Constrained Economic Dispatch is assumed for MISO and external systems for the baseline reliability studies. A Security Constrained Economic Dispatch simulates a market dispatch.

General procedure used for developing the SCED case:

- Review the transactions (drive-in and drive-out) modeled in the base case. Make changes as required to the transaction list through the MISO/MTEP model review process. The latest available ERAG MMWG series model is used to represent the external system. The neighboring system updates available through the regional coordination process will also be used to update the model as needed.
- Review the Control Area (CA) load levels modeled and update the load levels as necessary based on stakeholder input.
- Review the revised SCED case through the MTEP stakeholder review process for approval.

4.3.7 Short-term Planning Contingencies

A Typical Contingencies Evaluated in Support of Annual Reliability Assessments

Regional contingency files are developed by MISO planning staff collaboratively with Transmission Owner and supplemented by information obtained from stakeholders at SPMs, as appropriate. The list of contingencies will include events described under NERC TPL 001 through TPL-004, or any applicable local or RRO planning criteria or guidelines. Below is a list of typical contingency categories tested:

- NERC Category A is system intact or no contingency event.
- NERC Category B1-B4 faulted events for system under MISO operational control. Generally, greater than 100 kV, but includes some 69 kV. Category B includes single generator, transmission circuit and transformer outages. It also includes single pole block of DC lines.
- NERC Category C1, C2, and C4 through C9 faulted events. The more severe events will be studied per the standards. All events to be documented and studied over study cycle. Transmission Owners and MISO staff will document NERC Category C coverage.
- NERC Category C3 by control area including ties. This also includes double generator outages by control area. Selected generator plus branch C3 contingencies.
- NERC Category C from previous MTEP study which resulted in planning criteria violation (or exception) or used to justify upgrade project.
- NERC Category D events. Global automated bus outages to cover D8 and D9. Selected Category D events of other types to provide coverage over study cycle.

B Rationale for Contingencies Selected as More Severe

NERC standards require that studies are to be performed and evaluated only for those Category B, C and D 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. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

MISO applies the following principles in contingency selection:

- Where possible, evaluate all contingencies system wide within each Category
- Consider the input and expertise of our member Transmission Planners by incorporating their explicit contingency lists
- Supplement the explicit lists provided by our members with automated contingency generation to increase coverage
- For contingencies involving loss of more than one contingency, evaluate an extensive list of contingency combinations focusing on combinations of facilities that have a greater chance of impacting each other producing more severe results

Consistent with these contingency selection principles, the following contingencies are applied:

- All NERC Category B (single line, single transformer, or single generator outage) contingency events are to be analyzed in AC contingency analysis.
- All explicit category C1 (Bus Fault), C2 (Breaker Fault), C3 (Two independent overlapping single outages), C4 (Single Pole DC block) and C5 (Double circuit tower outage) contingent events generally deemed more severe than others and submitted by transmission owners. MISO additionally maps all B, C1 and C2 contingencies to substations to identify potential gaps in severe contingencies not otherwise defined. MISO planning staff works collaboratively with Transmission Owners to develop and then add these additional contingencies to the existing list.

- In addition to above explicitly defined Category C events, the following automatically generated events are also analyzed:
  - C3: Automatic Bus Double branch contingent events above 100 kV. Bus Double branch contingencies are combination of two branch outages from the same powerflow bus.
  - C3: Automatic Double Generator, Generator + Branch and Double Branch in two separate adjacent control areas with the following thresholds: Generators above 100 MW, Lines above 200 kV and transformers with low side above 200 kV.
- All Explicit category D contingent events generally deemed more severe than other by transmission owners are analyzed.

In addition to explicit Category D contingencies provided by Transmission Owners and considered for steady state analysis, automatically generated contingencies below deemed more severe Category D contingencies, provide supplemental coverage.

- D8 and D9: Global automated bus outages of all MISO member buses in each case
- D10: Loss of all generation at a plant was considered for large generating stations.

External Systems:

- Where MISO and non-MISO systems were highly integrated, contingencies on non-MISO systems were also analyzed for impacts on MISO members' systems.

4.3.8 Short-term Planning Reliability Testing

Reliability testing of the planned system focuses on ensuring that there is sufficient transmission capacity to serve the expected load at peak demand conditions. The system is tested using a peak power load flow model with a specific generation dispatch. MISO uses a security constrained economic dispatch, which is a market dispatch with renewable resource outputs set at the appropriate levels.

4.3.8.1 Steady-State Analysis

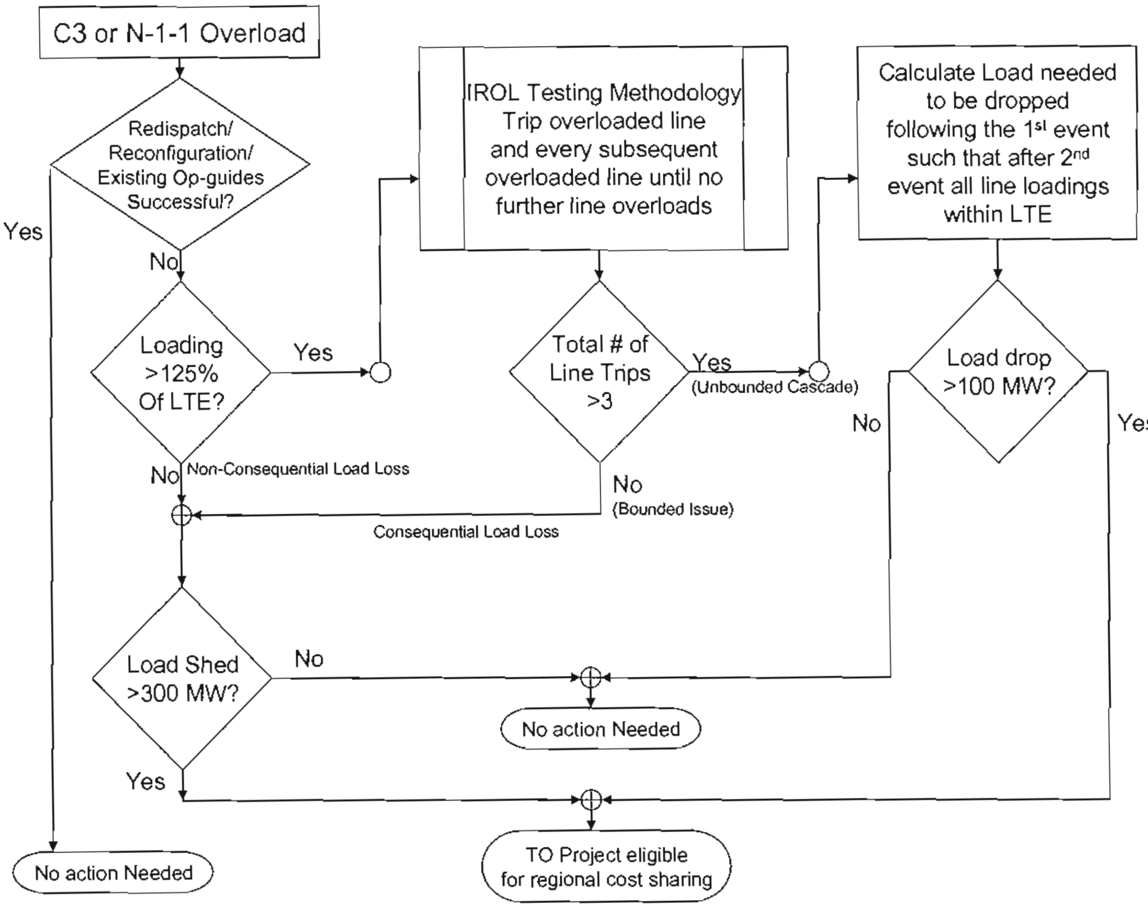
Steady-state Contingency Analysis will be performed on the initial planning models to test the contingencies of various categories described under Section 4.3.6 above. Thermal and voltage violations will be screened based on the applicable regional or local thresholds for a given condition and equipment.

Interconnection Reliability Operating Limit Identification:
Thermal overloads greater than 125% of emergency rating will be flagged and reviewed against applicable IROL criteria. MISO defines an IROL as follows:

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.

<u>Review Methodology Thermal Cascading for C3 Events</u>

The various steps involved in the Category C3 testing are shown in the flowchart below:



As a general rule, if a NERC Category C3 event results in a thermal overload or a voltage violation, redispatch (Process documented in Appendix J.5.1.1), system reconfiguration and any existing op-guides will be considered before testing load loss as potential mitigation option to mitigate constraint. If these options prove to be inadequate to completely mitigate overload, the original thermal overload would determine the testing method.

After the C3 event, if overload is greater than 125% of Long term emergency (LTE) rating of the line or transformer, IROL methodology documented earlier within this section 4.3.7 will be used.

- If greater than three lines need to be tripped in order to bring all line loadings within LTE, "Unbounded Cascade" test will be applied:
  - Load that needs to be dropped following the first of the two events such that there are no thermal or voltage constraints following the second event will be calculated
    - If this load loss is greater than 100 MW, transmission upgrades needed to alleviate constraints would be eligible of regional cost sharing
    - If this load loss is less than 100 MW, no further action to mitigate constraints is needed. If transmission owner still proposes a project that otherwise meet conditions documented in Appendix J 5.1.2, project may still be eligible for regional cost sharing. If other conditions are not met, transmission project may not be eligible for regional cost sharing
- If less than three lines need to be tripped in order to bring all line loadings within LTE, "Bounded Cascade" test will be applied. This test is the same as when line loading is greater than LTE but still less than 125% of LTE. The test will calculate load shed needed after the two events to completely mitigate all constraints.
  - If the load shed amount is greater than 300 MW, Transmission Owner project may be eligible for regional cost sharing
  - If load shed is less than 300 MW, no further action to mitigate constraints is needed. If transmission owner still proposes a project that otherwise meet conditions documented in Appendix J 5.1.2, project may still be eligible for regional cost sharing. If other conditions are not met, transmission project may not be eligible for regional cost sharing

Category C Issue Review In General

Category C events may result in loss of customer load. Category C3 events are typically simulated without the allowed system adjustment, therefore, those are considered exceptions until it is determined that the adjustment cannot mitigate the issue. The following items are part of the review of results of Category C event analysis:

- Review Category C issues which may be resolved by system reconfiguration, generation re-dispatch, or load shedding
- Document Category C events with existing operating guides
- Document Category C events which may be addressed by generation re-dispatch
- Document Category C events which would require load shed
- Develop transmission system upgrades for system needs, if necessary.
- Communicate events without guides to seasonal transmission assessment study team.

Review for Other forms of Instability

The system is evaluated for voltage and dynamic performance as described below.

4.3.8.2 Voltage Stability Analysis

In addition to contingency analysis of the base case, a separate voltage stability analysis is also performed in order to identify voltage stability limits and power margins. This will help identify "Soft Spots" or regions on the verge of voltage collapse, deprived of reactive resources under different system conditions. 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. The following general study procedure is used for this analysis:

- P-V and/or Q-V analyses for the selected study horizon and areas using the MTEP models
- Monitor voltages at substations, reactive reserves at significant units and flows on branches and known interfaces for critical contingencies under appropriate system stress conditions
- Identify and document potential voltage collapse conditions, areas with exhausted or limited reactive reserves and power margins

4.3.8.3 Dynamic Stability Analysis

MISO uses the PSS/E power flow model to perform dynamic stability simulations. MISO planning staff performs stability simulations on a 5-year planning horizon summer peak case, using contractual generation dispatch (described above) or a 5-year summer off-peak case with security constrained economic dispatch as specified in the current study scope and cycle.

MISO requests that Transmission Owners submit dynamic disturbance events in advance of the MTEP planning cycle. MISO requires that Transmission Owners submit NERC Category C (preferably with delayed clearing) events at all large generating plants (e.g., total plant rating greater than 150 Megawatts) in their system. Utilities with plants smaller than 150 Megawatts should submit disturbances for their two largest plants. Transmission Owners are also required to submit information on any known critical system disturbances which are not generation related, and select NERC category D contingency events per control area. Contingencies that do not solve in steady-state AC analysis and cannot be made to solve in individual power flow analysis are also evaluated with dynamic stability analysis.

MISO planning staff uses the member disturbance performance monitoring guidelines for monitoring the dynamic simulations. Many Transmission Owners in the West region use criteria that is different from the MISO proxy of a minimum damping ratio of 3%. (See Table 4.3-1 – notes associated with this Table can be found in Appendix K of this Manual.) MISO proxy damping criteria is also monitored in parallel.

A dynamic study model is based on the current MTEP 5-year planning horizon summer peak power flow case. A channel file is set to monitor system critical facilities including: large generation units, stability interfaces, and long-distance high voltage transmission lines (see Appendix K). The monitored generation list consists of the generators with Pmax larger than 75 MWs. The long-distance high voltages line list includes the transmission lines with voltage of 200 kilovolts and above and an estimated length of 40 miles or more. The channel file plots the voltage, phase angle and branch flow. Besides this common system channel file, each disturbance adds specific monitoring elements in the PSS/E Simulation Run Assembler file.

According to the Disturbance-Performance monitoring table, all the dynamic stability violations are reported. Projects which would mitigate the identified system need are documented.

Table 4.3-1: Disturbance Performance Monitoring Guidelines for Dynamic Simulations

NERC Event Cat.	Transient Voltage Deviation Limits (up to 20 seconds)	Post Transient Voltage Deviation Limits (20 seconds to 30 Minutes)	Post Transient Facility Seasonal Loading Limits (20 seconds to 30 minutes)	Rotor Angle Oscillation Damping Ratio Limits (up to 20 seconds)	Out-of-Step Relay Trip Margin Limits (up to 20 seconds)
A	Nothing in addition to NER Requirements: 1. Bulk transmission bus voltage level between 0.95pu and 1.05pu of the nominal voltage base of the system, except as noted in the MAPP members reliability criteria and study procedures manual; 2. Facility loadings will not exceed 100% of the normal rating (rate A) for lines or 100% of the normal rating for transformers.				Not to be less than 110% (Canada-U.S interface, see note 10)
B	$0.7 \leq V_{bus} \leq 1.2$	$0.9 \leq V_{bus} \leq 1.1$	Line_loading ≤1.1*rateB Trx_loading ≤1.25*rateB	West With Fault: $\zeta_i \geq 0.0081633$ No fault line trip: $\zeta_i \geq 0.0167660$ **MISO criteria**: $\zeta_i \geq 0.03$	Not to be less than 25% (Canada-U.S interface, see note 10)
C	$0.7 \leq V_{bus} \leq 1.2$	$0.9 \leq V_{bus} \leq 1.1$	Line_loading ≤1.1*rateB Trx_loading ≤1.25*rateB	West With Fault: $\zeta_i \geq 0.0081633$ No fault line trip: $\zeta_i \geq 0.0167660$ **MISO criteria**: $\zeta_i \geq 0.03$	Not to be less than 25% (Canada-U.S interface, see note 10)
D	Nothing in addition to NERC requirements				

4.3.8.4 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 identified load zones within the MISO Reliability Authority footprint have sufficient capacity to meet the 1 day in 10 years LOLE reliability criteria. Stated below is a general definition for this criterion.

> *"The loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year or not more than once in ten years."*

The factors taken into consideration in performing the LOLE analysis, include following.

- Uncertainty of the load forecast due to weather and economic conditions
- Forced outage rates and scheduled maintenance for the various generating resources
- Seasonal variations and capacity de-ratings of generating resources
- Emergency operating procedures for maintaining system reliability
- Transmission capacity and transfer capabilities of the interconnected Transmission System

Appropriate load zones for the MTEP LOLE study are selected based on stakeholder input through the planning process. This section of the BPM may be updated as appropriate when the LOLE methodologies related to Module E are finalized.

General methodology used for the MTEP LOLE study is as follows.

- Determine the LOLE for the selected zone on a stand-alone basis (no ties)
- If LOLE is less than target (0.1), determine the required tie capability between the zone and the remainder of the MISO system for the zone LOLE to be at target (0.1)
- Compare the required tie capability to the projected tie capability from the MTEP models for the study years

- If the tie capability is below the tie requirement, one or more of the following may be applicable
  i) LSE has contracted with the required amount of generation resources as per Module E, and the transmission deliverability of those resources has been established (generation is Deliverable, TSR exists, or First Contingency Incremental Capability (FCITC) into the zone is not exceeded by amount of resources under contract that are external to the zone), but additional import capability beyond the FCITC is needed to access emergency assistance generation during generation deficiencies within the zone that occur on a "once-in-ten" (1 day in 10 year) basis.
  ii) LSE has not contracted with (including owned generation) the required amount of generation resources as per Module E, and is therefore relying on generation of others for which transmission delivery has not been arranged
  iii) LSE has contracted for the required amount of generation resources as per Module E, but the transmission delivery capability of those resources to the load has not been arranged for (I.e. tested for and developed via the TSR or Module E processes).
- Develop transmission tie expansions needed for the required import capability (LOLE driven) and categorize as Baseline Reliability Projects, for Case (i) above, where the tie deficiency is needed to meet emergency import needs for an LSE that has otherwise satisfied Module E and transmission delivery requirements.
- For Cases (ii) and (iii) above, generation and transmission arrangements are the responsibility of the LSE, and any transmission expansions needed may be categorized as other non-BRP transmission expansions defined in Section 2.4 of this BPM.

4.3.8.5 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, that is, without 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) could be designated by any LSE within the Midwest Market Footprint to satisfy its Resource Adequacy requirement as specified in Module E of the EMT.

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 Attachment B.6 of the Business Practices Manual for 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.

4.3.8.6 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.

4.3.9 Long-term Transmission Rights Feasibility Review

A 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 – Manual No. 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.

B 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 4 seasonal cases in both peak and offpeak 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.

B.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 and Pricing Administration group and MISO planning staff. The following information will be provided to the FTR and Pricing Administration by MIOS 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 and Pricing 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.

B.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 5-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 transmission expansion planning group. 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.

B.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 in planning models to occur. 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 and Pricing Administration group will attempt to determine the cause of the infeasibility in the LTTR allocation process.

C 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 4.3-1 provides a guide to these combined integrated processes. The first year ARR / LTTR allocation will determine the allocation of feasible LTTRs. Figure 4.3-1 is applicable to the second and subsequent year allocations.

C.1 ARR Allocation Process - First Year LTTR Allocations

The FTR and Pricing 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 Expansion Planning group by the FTR and Pricing 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.

ARR Allocation / MTEP Planning Processes

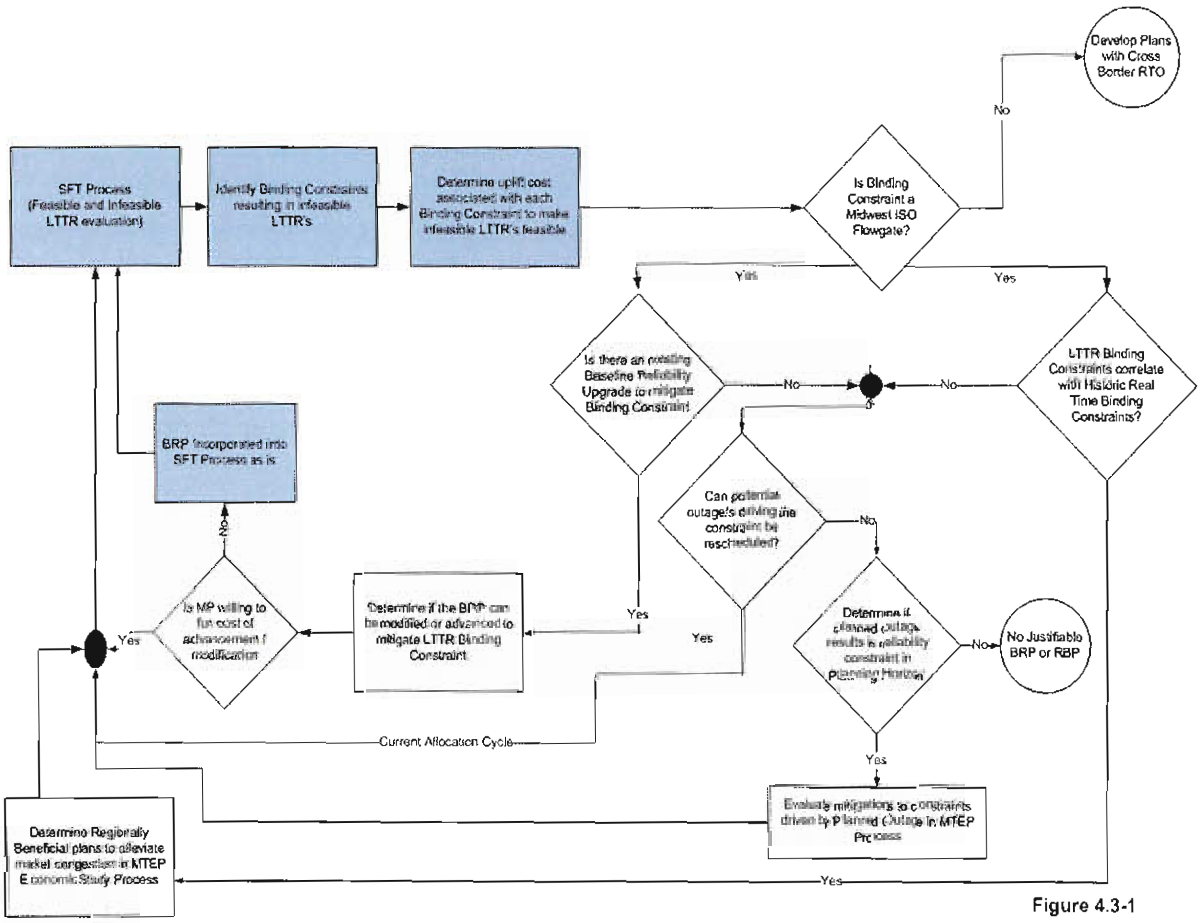


Figure 4.3-1

C.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 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 2 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 ARRs / LTTRs allocation, the FTR and Pricing 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 and Pricing 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.

C.3MTEP Process - The Second and Subsequent Year Planning Models

As indicated in Figure 4.3-1, the MISO planning staff will use the various MTEP models to evaluate Flowgate constraints.

Near-term Planning / 1 – 2 Year Planning Horizon

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

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 justifiable 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.

4.3.10 Economic Evaluation of Potential Projects for the Short-term Planning Horizon

BRPs will be considered in the short-term planning process if they resolve a Transmission Compliance Issue that commences in the short-term planning horizon, where the short-term planning horizon is generally considered the greater of five years or the lead time of the project under consideration. In selecting BRPs for consideration for the short-term plan, consideration should be given to the incremental value of one alternative over another, where incremental value is defined as the present value of the incremental financially quantifiable benefits of an alternative project evaluated over the first 20 years of the project's life less the present value of the incremental annual revenue requirements of the alternative project evaluated over the first 20 years of the project's life. MEPs will be considered in the short-term planning process if some level of economic value can be realized within the short-term planning horizon on an annualized basis. Multi Value Projects (MVPs) will be considered in the short-term planning process if they resolve one or more Transmission Compliance Issues within the short-term planning horizon when qualifying under Criterion 1 or Criterion 3 or address one or more Transmission Value Issues within the short-term planning horizon when qualifying under Criterion 2 or Criterion 3, that is, begin generating positive economic value within the short-term planning horizon. All of these projects represent projects that have been studied under the long-term transmission process and have been transferred into Appendix B of the current or a previous MTEP.

Projects that qualify as MVPs under Criterion 2 or Criterion 3 should be considered for the Short-term Transmission Plan if they provide a Total MVP Benefit-to-cost Ratio of 1.0 or better. The Total MVP Benefit-to-cost Ratio of a specific MVP is based on the present value of annual financially quantifiable benefits and the present value of annual revenue requirements over the first 20 years of the project's life using a risk adjusted discount rate for the present value calculation.

The formula for the Total MVP Benefit-to-cost Ratio of an MVP is as follows:

$$\text{TotalMVPBC} = \sum_{yr} \{\text{PVProjectFinBen}(yr)\} / \sum_{yr} \text{PVProjectRevReq}(yr)\}$$

where

yr = Index of first 20 years of project life

PVProjectFinBen(yr) = The present value of the annual financial benefit calculated for the project in year *yr* based on a risk adjusted discount rate to be determined by the MISO.

PVProjectRevReq(yr) = The present value of the annual revenue requirements calculated for the project in year *yr* based on a risk adjusted discount rate to be determined by the MISO

In selecting potential projects for the short-term plan that qualify as MVPs based on Criterion 1, consideration should be given to the incremental value of one alternative over another, where incremental value is defined as the present value of the incremental financially quantifiable benefits of an alternative project evaluated over the first 20 years of the project's life less the present value of the incremental annual revenue requirements of the alternative project evaluated over the first 20 years of the project's life. For all MVPs, consideration should also be given to the long-term planning strategy selected for the Transmission System as a whole.

The specific type of financially quantifiable benefits associated with Transmission Value Issues addressed by an MVP, include the following:

- 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 energy losses. Productions cost savings can also be realized through reductions in Reserve Zone Operating Reserve requirements and, in some cases, reductions in overall Operating Reserve requirements. Production cost savings will be based on simulations using a production cost model with and without the project modeled under the reference future. Production cost savings will be determined for each of the first 20 years of a project's life.
- Capacity losses savings where capacity losses represent the amount of resource capacity required to serve transmission losses during the system peak hour. Reductions in MW losses during the system peak hour can be determined for a specific year using load flow simulations with and without the project modeled. The value of the loss reduction in a specific year can be determined by multiplying the transmission losses reduction in MW during the system peak hour by the product of the projected value of the CONE (Cost of Next Entrant) for the year and a factor equal to one plus the projected Planning Reserve Margin for the year.
- Capacity savings due to reduced Planning Reserve Margins. Planning Reserve Margin reductions can be estimated by executing Loss of Load Expectation studies with and without a specific project modeled and then multiplying the resulting reduction in the Planning Reserve Margin for the year by the product of the projected system peak demand for the year and the projected value of the CONE (Cost of Next Entrant) for the year.

- Long-term cost savings realized by accelerating a long-term project target date in lieu of implementing a short-term project in the interim. This analysis compares the present value of the life-cycle cost of the short-term project vs. the present value of the cost of accelerating the long-term project.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System that is directly related to providing Transmission Service.

As each project is being considered for movement from Appendix B into Appendix A, sensitivity analyses may be performed if necessary to ensure recommended projects are effective under alternative future scenarios, where alternative future scenarios represent different assumptions regarding which projects currently in Appendix B may ultimately move to Appendix A.

4.3.11 Alternative Short-Term Plans

A "plan" represents the collection of projects that are candidates for recommendation for implementation to the Transmission Provider Board in the current planning cycle. To the extent that there are alternative short-term plans under consideration that resolve all Transmission Compliance Issues in the short-term planning horizon, these alternative short-term plans will be compared using the approach of Section 4.3.11. It is expected that most of the projects within an alternative short-term plan will be common to all alternative short-term plans (e.g., reliability based projects developed from the bottom-up planning process), but there may be differences in alternative short-term plans based on alternative sets of Dependent Transmission Projects developed in the long-term planning process, e.g., more than one variation on a 345 kV or higher voltage portfolio designed to address a particular long range requirement. [Dependent Transmission Projects are discussed in Section 2.3, MTEP Appendix A (III).] Alternative sets of Dependent Transmission Projects are expected to arise in the long-term planning process primarily as the result of alternative long-term plans developed to facilitate renewable energy standards, other public policy objectives and/or opportunities to enhance economic value for the entire MISO footprint. It is expected that only a subset of the projects included in Appendix B from the long-term planning process will be included in the alternative Short-term Transmission Plans within a given planning cycle as the key objectives of the alternative Short-term Transmission Plans are to resolve only the Transmission Compliance Issues and Transmission Value Issues that commence in the short-term planning horizon, but in a manner that optimizes the value of transmission over the long-run.

It is important to note that development of alternative Short-term Transmission Plans will be a highly collaborative process between MISO planning staff, Transmission Owners and other stakeholders and will be facilitated through SPMs, the Planning Subcommittee and the Planning Advisory Committee.

4.3.12 Selection of the Preferred Alternative Short-Term Transmission

As discussed in Section 2.3 (III) of this document, selection of the preferred alternative Short-term Transmission Plan, which is equivalent to selection of the specific projects to be included in Appendix A of the MTEP, is based on the following process:

4.3.12.1 Determine the Total Financial Value of each Alternative Short-Term Transmission Plan

The first step is to determine the total financial value of each alternative Short-term Transmission Plan using the following formula:

$$\text{TotalValue}(pl) = \sum_{yr} \{\text{PVRefPlanARR}(yr) + \text{PVAnnualFinBen}(pl,yr) - \text{PVARR}(pl,yr)\}$$

where

pl = Index of alternative Short-term Transmission Plans being evaluated

yr = Index of first twenty years of a Short-term Transmission Plan

TotalValue(pl) = The present value of the total financial value generated by alternative Short-term Transmission Plan *pl* expressed in dollars and based on a risk adjusted discount rate to be determined by MISO.

PVRefPlanARR(yr) = The present value of the annual revenue requirements in year *yr* of the reference alternative short-term plan, where the reference alternative Short-term Transmission Plan is the Short-term Transmission Plan with the lowest present value of annual revenue requirements over the first 20 years of the plan's life based on a risk adjusted discount rate to be determined by MISO.

This term represents the reference economic value of resolving Transmission Compliance Issues and is assigned to each alternative Short-term Transmission Plan since each alternative Short-term Transmission Plan must resolve all Transmission Compliance Issues.

PVAnnualFinBen(pl,yr) = The present value of the annual financially quantifiable benefits of alternative Short-term Transmission Plan *pl* in year *yr* based on a risk adjusted discount rate to be determined by MISO.

and

PVARR(pl,yr) = The present value of the annual revenue requirements of alternative Short-term Transmission Plan *pl* in year *yr* based on a risk adjusted discount rate to be determined by MISO.

The annual financially quantifiable benefits of an alternative Short-term Transmission Plan which results from resolution of Transmission Value Issues within the alternative Short-term Transmission Plan may include the following:

- 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 energy losses. Productions cost savings can also be realized through reductions in Reserve Zone Operating Reserve requirements and, in some cases, reductions in overall Operating Reserve requirements. Production cost savings will be based on simulations using a production cost model to test each alternative Short-term Transmission Plan under each Future which has been modeled in the long-term planning process. A weighted average production cost based on the probabilities of each Future modeled in the long-term planning process will be used. Production cost savings will be determined for each of the first twenty years of each alternative Short-term Transmission Plan.

- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour. Reductions in MW losses during the system peak hour can be determined for a specific year using load flow simulations of each alternative plan. The value of the loss reduction in a specific year can be determined by multiplying the transmission losses reduction in MW during the system peak hour by the product of the projected value of the CONE (Cost of Next Entrant) for the year and a factor equal to one plus the project Planning Reserve Margin for the year.
- Capacity savings due to reduced Planning Reserve Margins. Planning Reserve Margin reductions can be estimated for a specific year by executing Loss of Load Expectation studies for each alternative Short-term Transmission Plan and then multiplying the resulting reduction in the Planning Reserve Margin for each year by the product of the projected system peak demand for the year and the projected value of the CONE (Cost of Next Entrant) for the year.
- Long-term cost savings realized by accelerating a long-term project start-date in lieu of implementing a short-term project in the interim. This analysis compares the present value of the life-cycle cost of the short-term project vs. the present value of the cost of accelerating the long-term project.
- Any other financially quantifiable benefit to Transmission Customers related to the provision of Transmission Service resulting from an enhancement to the Transmission System.

4.3.12.2 Determine the Total Plan Benefit-to-Cost Ratio of each Alternative Short-Term Plan

The second step is to determine the Total Plan Benefit-to-cost Ratio of each alternative Short-term Transmission Plan using the following formula:

TotalPlanBC(pl)

$$= \sum_{yr} \{PVRefPlanARR(yr) + PVAnnualFinBen(pl,yr)\} \;/ \sum_{yr} \{PVARR(pl,yr)\}$$

where

pl = Same as formula in Section 4.3.11.1
yr = Same as formula in Section 4.3.11.1
TotalPlanBC(pl) = The Total Plan Benefit-to-cost Ratio associated with alternative Short-term Transmission Plan *pl*
PVRefPlanARR(yr) = Same as formula in Section 4.3.11.1
PVAnnualFinBen(pl,yr) = Same as formula in Section 4.3.11.1
PVARR(pl,yr) = Same as formula in Section 4.3.11.1

4.3.12.3 Develop a Final List of Alternative Short-Term Transmission Plans for Further Review

A final list of alternative Short-term Transmission Plans will be developed as follows:

- The alternative Short-term Transmission Plan that produces the highest Total Plan Value as determined in Section 4.3.11.1 of this document will be placed on the final list.
- The alternative Short-term Transmission Plan that produces the highest Total Plan Benefit-to-cost Ratio as determined in Section 4.3.11.2 of this document will be placed on the final list.
- Any alternative Short-term Transmission Plan with a Total Plan Value not less than 75% of the highest Total Plan Value of all alternative Short-term Transmission Plans and a Total Plan Benefit-to-cost Ratio not less than the 75% of the highest Total Plan Benefit-to-cost Ratio of all alternative Short-term Transmission Plans will also be placed on the final list.

4.3.12.4 Select the preferred Short-term Transmission Plan

After development of the final list of alternative Short-term Transmission Plans, the following factors will be considered by MISO planning staff to select the preferred alternative Short-term Transmission Plan for recommendation to the Transmission Provider Board:

- Consideration of how well the alternative Short-term Transmission Plan fits into the overall long range transmission expansion strategy.
- Feedback from Transmission Owners and other stakeholders on the merits of each alternative Short-term Transmission Plan.

- Comparison of the Total Plan Value calculated for each alternative Short-term Transmission Plan
- Comparison of the Total Plan Benefit-to-cost Ratio calculated for each alternative Short-term Transmission Plan
- Non-financial quantifiable factors such as (but not limited to) the amount of new right-of-way required for each alternative Short-term Transmission Plan.
- Qualitative factors such as (but not limited to) the longevity or overall robustness of each alternative Short-term Transmission Plan.
- Regulatory risk factors such as (but not limited to) the number of state approvals required to implement each alternative Short-term Transmission Plan
- Other pertinent information that may be applicable.

Once the preferred Short-term Transmission Plan has been selected, all projects associated with the preferred Short-term Transmission Plan will be flagged to move to Appendix A of the applicable expansion plan for approval by the Transmission Provider Board. That is, the projects moving to Appendix A of a specific MTEP represent the recommended Short-term Transmission Plan for that MTEP.

4.4 Long-term Planning

4.4.1 Market Efficiency Project Introduction

Long-term planning focuses on ensuring an optimum long-term transmission expansion plan. Long-term planning focuses on robustness under future uncertainty, long-term policy objectives and strategies to assist in maximizing the value of the Transmission System over the long-run. Unlike short-term plans, long-term plans are not yet approved for construction, but instead are implemented in phases by integrating long-term planning results into a series of optimized short-term plans. The key objective of long-term planning is to develop optimal long-term solutions that can guide and, when appropriate, be integrated into short-term plans for implementation.

4.4.2 Process Steps for Long-term Planning

The long-term planning process takes a long-term view of Transmission Issues to establish an efficient plan that is value driven, and when integrated with shorter-term plans endeavors to produce the most efficient and reliable Transmission System achievable. The flow of this process is outlined below in Figure 4.4-1 and consists of the following steps. The detailed process flow diagram is outlined in Figure 4.4-2.

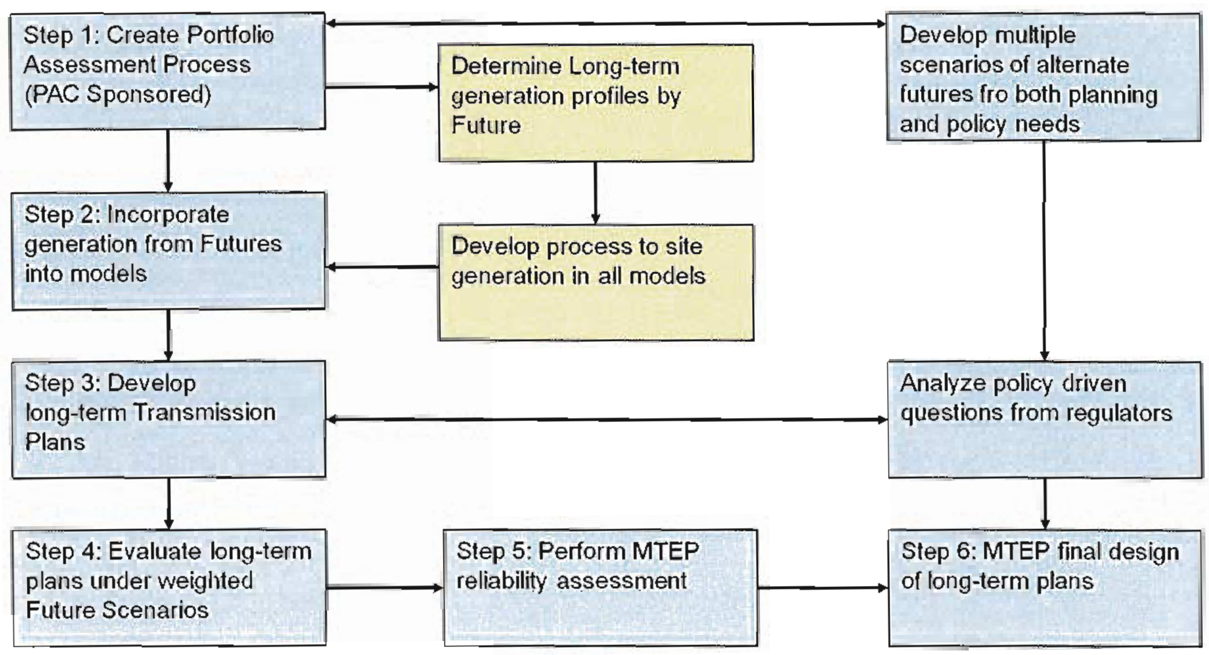


Figure 4.4-1 Process Diagram – Integrating Reliability Requirements with Economic Efficiency Goals

4.4.2.1 Create a generation portfolio forecast and assessment process

The MISO Generation Interconnection Queue provides initial information into new generation being proposed within the footprint. This is supplemented a) resource requirements driven by regulatory mandates, state laws and/or federal laws (e.g., State Renewable Portfolio Standards, etc.), and b) with other intelligence on new generation projects and long-range integrated resource plans not yet reflected in the MISO Generation Interconnection Queue. Generation portfolio assessments are developed for each of the three planning regions within MISO.

4.4.2.2 Incorporate generation from Futures into models

Once the future generation from the portfolio assessment process is identified, it must be sited. Transmission planning models used by MISO require that new generating units must have their physical location and interconnection characteristics specified in order to establish initial reference conditions. New generating units in the Generation Interconnection Queue have known sites and specific interconnection parameters.

With regard to future generation not yet in the Generation Interconnection Queue, a resource's site and/or transmission interconnection infrastructure is not yet known. In these cases, MISO planning staff must develop assumptions about the new resource's location and interconnection features under a number of alternative futures.

For its long-range planning studies, MISO planning staff identifies likely sites for new generating resources, and presumes that new interconnecting transmission facilities will be constructed as necessary to support generating plants that may not be located adjacent to existing transmission facilities. MISO also considers the existing Renewable Energy Zones when determining potential sites for renewable resources needed to meet renewable portfolio standards. This 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 will 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.

4.4.2.3 Design preliminary long-term transmission plans

Each alternative Future is first simulated through power flow modeling to estimate loads and generating capacity requirements. Results from this simulation are then input into a production cost model that estimates the cost to generate and transmit electric power to customers. This modeling assumes a "copper sheet" transmission system, with no constraints, so that power flows unrestricted from generators to loads. Load flow and generation dispatch estimates from this initial round of modeling are used to simulate one or more hypothetical high voltage overlay sufficient to meet projected energy flow requirements. Further modeling of hourly load flow estimates is used to refine the size and characteristics of the alternative long-term transmission plans. Hourly flow information is also combined with transmission constraint identification tools linked to the production cost model to iteratively refine the long-term transmission plans. Each of these modeling processes is performed collaboratively with stakeholders in an open planning process. Projects associated with each of the preliminary long-term transmission plans will be subjected to the effectiveness testing described in Section 2.3 (II) to ensure they effectively address one or more future Transmission Issues. All projects associated with the alternative long-term plans that demonstrate the ability to effectively address one or more future Transmission Issues based on this effectiveness testing will be placed into Appendix B.

4.4.2.4 Evaluate alternative long-term transmission plans for resolution of Transmission Compliance Issues

The process described in Step 3 produces one or more alternative long-term transmission plans. It is necessary that each alternative long-term plan resolve key Transmission Compliance Issues under all Futures. To this end, each preliminary long-term transmission plan is analyzed under the uncertainty conditions of every Future scenario to ensure it resolves key Transmission Compliance Issues, where key Transmission Compliance Issues will be established by MISO and Transmission Owners and represent those Transmission Compliance Issues that require major expansions or modifications to the Transmission System to gain compliance. A long-term transmission plan that resolves the key Transmission Compliance Issues under every Future scenario is considered robust with regard to Transmission Compliance Issues. To the extent that key Transmission Compliance Issues are not satisfied by a specific alternative long-term plan, MISO will work with Transmission Owners and other stakeholders to make necessary adjustments to the alternative long-term plan.

Each transmission plan is tested for robustness by evaluating its performance under every Future scenario and assessing its test results for selected attributes that may include the following:

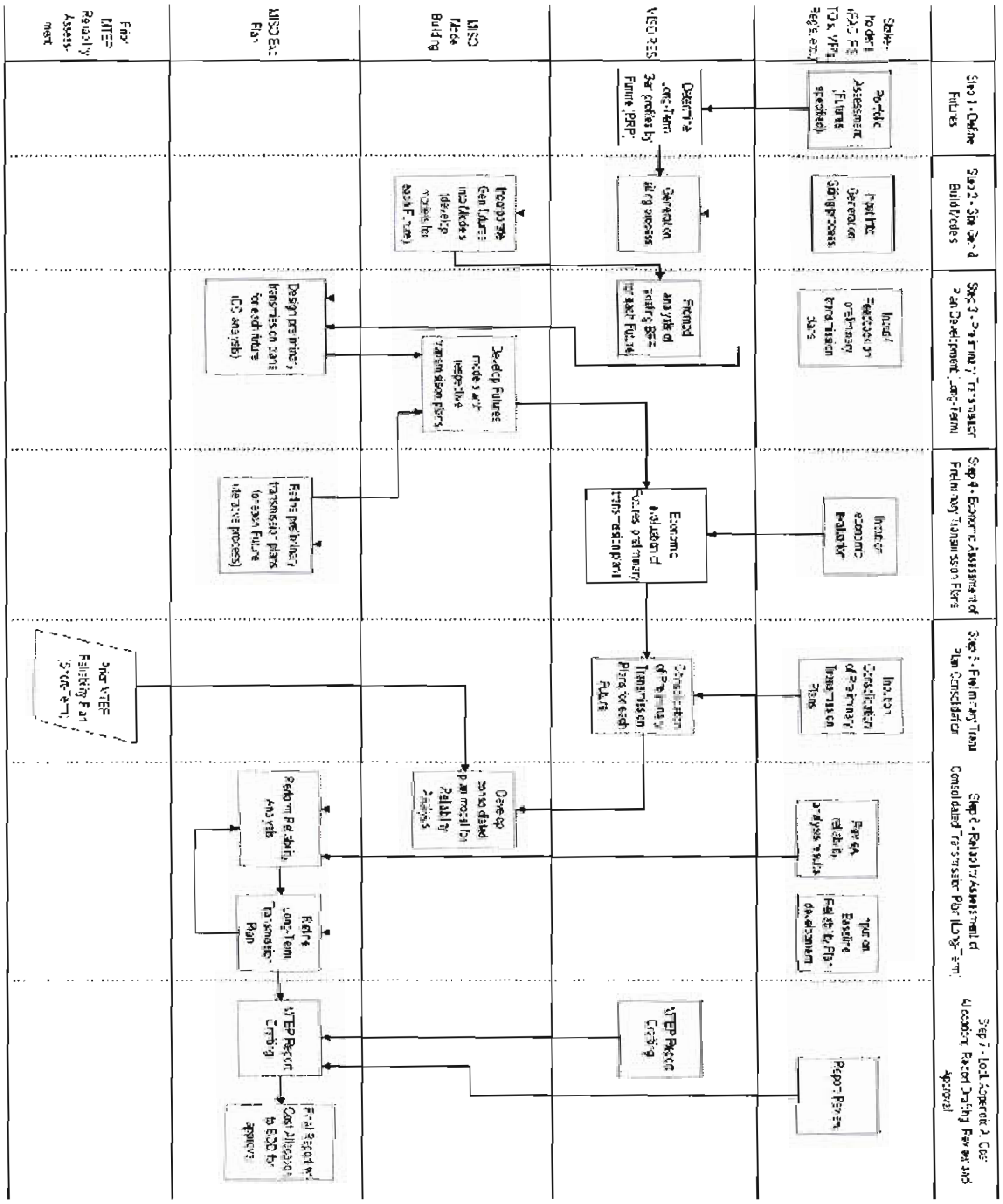
- LOLE / Reserve margin effects
- Short and long-term cost metrics
- Investor impacts
- Economic development impacts
- Degree of difficulty in developing
- Environmental compliance
- National security issues

Potential transmission plans are ranked according to their performance on these attributes to determine which was most robust under the Future scenarios considered.

4.4.2.5 Evaluate Long-term Transmission Plans for Transmission Value Robustness

All alternative long-term plans that resolve the key Transmission Compliance Issues outlined in Step 4 will be analyzed for value, where value represents the difference between benefit and cost. In general, financial benefits considered during this step include, but are not necessarily limited to, production cost savings, reserve margin reductions and capacity losses reduction. In analyzing these financial benefits, analysis will be completed under multiple Futures to ensure robustness. Each future will have a weighting factor applied based on the likelihood of that future relative to other futures, and overall financially quantifiable benefits will be determined by applying these weighting factors to the financial benefits determined for each future to determine a weighted average benefit. The weighting factors to be applied to each future will be determined by MISO working in collaboration with the Planning Advisory Committee. The alternative long-term plan that, in the judgment of MISO planning staff based on preliminary analyses provides the highest level of long-term value will represent the modeled long-term plan. While the modeled long-term plan will include projects in Appendix A and Appendix B, the modeled long-term plan in general is not yet approved for construction. All projects in Appendix A are also associated with the current or a previous short-term plan which is approved for construction. That is, the current and previously approved short-term plans that have not yet been implemented are subsets of the modeled long-term plan. However, the modeled long-term plan will also include projects that have not yet been approved for construction. These projects are located in Appendix B of the current expansion plan and designated with an asterisk. It is important to emphasize that the modeled long-term plan is not yet approved for construction, but instead represents the default long-term plan at a single point in time. Only short-term plans, which are guided by the results of long-term planning, are approved for construction. Long-term plans will change over time and will guide development of the short-term plans.

Figure 4.4-2 – Futures and MEP Development – Process Flow Diagram



4.4.3 Data Sources and Assumptions for Long-term Planning Models

The data for the long-term planning studies are from a central database. The initial data (load, generator, fuel, and environmental data) in database are provided by a vendor. The vendor also provides incremental updates on the data each month and a large update once a year. The vendor data can 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 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

4.4.3.1 Demand and Energy

MISO planning staff replaces the company peak demand and energy data provided by the vendor with the latest Module E reported data. Included in the Module E data are Interruptible Load, Direct Load Control, and 10 year projections for demand by each company. Module E load data includes losses.

The demand for each Local Balancing Authority is the non-coincident value reported to MISO for resource adequacy reporting. This data is reported to MISO each year and represents the non-coincident peak demand for each company. The hourly load profile for each company will use the load profile from the vendor-supplied data. Module E only provides 10 years of load forecast data. Each individual company's Module E reported growth rate over the first 10 year period is averaged and extended over the remaining 10 years of the study period.

Individual company's annual energy requirements are calculated based on its demand and its load factor reported in the latest Module E (based on the report year's demand and energy).

4.4.3.2 Generation Data

Areas outside MISO are modeled using the generation information in the vendor database. Generation within MISO is adjusted to represent what is reported through the resource adequacy provisions of Module E. Changes include activating or deactivating units and adjusting the maximum capacity of the unit. All other operating characteristics use the default data from the vendor. In addition to generator changes reported through the resource adequacy process, generators in the MISO Queue which have a signed interconnection agreement (IA) are modeled. The new generators identified in Step 1 and Step 2 are also being included in later steps study.

4.4.3.3 Fuel Data

The source for the fuel forecasts in the vendor database is typically the Platt's database, Henry hub forecasts, and EIA forecasts. The vendor contracts with Platt's for various fuel forecasts. The vendor uses the Platt's forecasts for natural gas as a starting pointing and then uses the basis differential inherent in Platt's forecast for Natural Gas combined with NYMEX Henry Hub futures prices for the first 18 months of the forecast. For the forecast beyond 18 months, the Energy Information Administration (EIA) natural gas forecast for the Henry Hub serves as the base index. The basis differential to each area is then applied against the EIA forecast of the Henry Hub prices.

The oil forecasts are based on futures contracts with no basis differential. Heavy Oil forecasts in this PROMOD study are adjusted based on Crude Oil prices and Light Oil forecasts are adjusted based of Heating Oil prices from NYMEX.

The coal forecasts are from Platts directly and these forecasts include transportation costs.
The vendor updates the fuel forecasts every quarter.

4.4.3.4 Environmental Data

Emissions production rates for an effluent are spread across all fuels assigned to a generator. Price forecast data is provided for SO2 and NOX (by trading program) emission allowances. All this data is from the vendor database.

4.4.3.5 Event File

Monitored Flowgates in PROMOD constitute an "event file". The source for this event file is MISO Book of flowgates and NERC Book of flowgates. Certain flowgates may have operating guides associated with them in real time operations. Hence the "event file" is scrubbed to remove any flowgate that might have an operating guide associated with them. Besides these flowgates, PROMOD Analysis Tool (PAT) is also used to identify new flowgates with overflow potential in study years and add them in the event file.

4.5 Regional 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 analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

The Inter-Regional Planning Stakeholder Advisory Group (IPSAG), 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 IPSAG also exchanges data regarding planning model assumptions for system performance, interface expansions, and network contingencies. The meeting notifications, schedules, and materials of IPSAG meetings are communicated to the stakeholders via Planning Sub-committee and Planning Advisory Committee email exploder lists.

4.6 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 take 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 do not restudy renewal transmission service requests. Upon receiving such requests, the MISO planning staff verify and ensure that the parameters of the renewal TSRs match 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 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 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 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 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 3% impact on the OTDF or greater than 5% 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 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 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 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 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 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:

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.

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.
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.

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 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

STEP 1: MISO will send the transmission customer an SIS agreement (SISA) within 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.

STEP 2: The transmission customer is required to execute and send the SIS agreement (SISA) back to MISO within 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 15 days from the time MISO makes that request, MISO shall refuse the TSR on OASIS. If the 15th day happens to be either on a weekend or a holiday, then MISO engineers will use 10AM of the next first Business Day as the deadline to accept the SISA.

STEP 3: If MISO receives the SISA within 15 days, then it will start the SIS and complete the study within 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 year request or starting after the first 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-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 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.

1. If the start date and the end date of the TSR are within the next 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.
2. If the start and end date of the TSR are beyond 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.
3. If the start date of the TSR is within the next 18 months of the queued date and the end date is beyond the next 18 months of the queued date, MISO uses the OASIS Automation tool and the offline analysis.

4. 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.
    a. If the start date and the end date of the TSR is within the next 18 months of the queued date, and there are negative AFCs on any Flowgate, then MISO will refuse the transmission service.
    b. If the start date of the TSR is within the next 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 1 year.

5.3.2.2 Network Analysis Concepts

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 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 5 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 owners 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 continuous rating or applicable rating for system intact conditions will be populated into NORM rating field of MOD. Emergency rating or applicable rating for contingent conditions will be populated in STE rating field. For purposes of planning model building, the STE field in MOD stands for Emergency rating or applicable rating for contingent conditions. When producing power flow models from MOD, Rate A will be populated with NORM rating from MOD and Rate B will be populated with **STE (emergency)** rating from MOD for appropriate season.

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.

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."

I) 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:

1. 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.
2. 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.
3. 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.

II) 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 Area, 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 different 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 PTI's MUST software.

Contingencies to Evaluate

Single line outages of facilities 100kV 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 69kV 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 owners. 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.

Monitored Elements

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

Reliability Margins (TRM/CBM)

MISO will apply the Reliability Margins provided by transmission owners. 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 Authority Areas will be modeled by reducing the branch ratings on pre-defined flowgates by the designated CBM margin provided for that facility.

Transfer Simulation Participation Points

Transfers will generally be simulated with a Local Balancing Authority Area 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.

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 above. The post-transfer case is created by adding the capacity of the requested transmission service request to the pre-transfer case.

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 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.

DC Analysis – Creating pseudo Flowgates using DC Analysis:

The following steps takes 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 20%, i.e., at most 15 generators can be called on to their Pmax. Therefore, up to 15 generators with GSFs greater than 5% are dispatched to their Pmax (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.

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 5% distribution factor of the study transfer on a facility overloaded beyond the applicable rating for system intact conditions, or a 3% 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).

SIS Report

MISO shall prepare the SIS report within Tariff guidelines and provide the report to the customer within 60 days after receiving the SISA and the study deposit. See the appendix B for the SIS report format.

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:

1. Provide comments on the study models developed by the engineers for the near term and out year scenarios
2. Provide comments on the overloaded transmission elements and provide mitigation which can include the following
    a. Provide correct rating for the equipment
    b. Identify existing transmission operating guides
    c. Identify approved projects that mitigate the thermal constraint
    d. Identify any existing Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) that are in place
3. 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
4. Provide preliminary cost estimates for fixing the overloads on transmission elements.

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.

1. 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 owners. The customer must submit the Specification Sheets within 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.
2. 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.
    a. 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 18 months to verify when the partial transmission service is available. If there are no negative AFC values for the next 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 12

consecutive months, so if negative AFC is found for any of the first 12 months of the request the counteroffer will be zero for the first 12 months. The customer can submit monthly firm transmission service requests for those months in the 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 15 days along with the Specification Sheets.

b. 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.

3. 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.
4. 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 18 months of the queued date of the requested TSR, then MISO planning staff will request the customer to submit Specification Sheets within 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.

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

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 5% distribution factor with system intact, or 3% under contingent conditions. Regardless of the distribution factor, any impacts under 1MW will be ignored.

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 owners of the need for study. These transmission owners 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, 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 30 days of completion of the SIS. If the facility study agreement is not executed within 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 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. MISO then prepares the study cost estimate, project timeline, and study agreement.

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

i. The cost of direct assignment facilities to be charged to the transmission customer
ii. The transmission customer's appropriate share of the cost of any required network upgrades
iii. 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.

i. It can either opt for a reduced amount of available transmission service, as identified in the SIS report.
ii. 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.
iii. Withdraw the TSR

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 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 Authority Areas as well as interested intervening Local Balancing Authority Areas. 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 Owners 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:
http://www.midwestmarket.org/publish/Folder/2220c2_108155d446d_-72290a48324a?rev=1
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 15 Calendar Days after initiating the request. Customer's failure to submit the Specification Sheets within 15 Calendar Days will result in the refusal of the TSR on MISO's OASIS.

5.5.2 Redispatch Options

The transmission customer does have the option for requesting MISO to perform a re-dispatch option study during the SIS phase. The goal of this additional step of analysis is to find out which generators, within MISO and external to MISO, can be re-dispatched in real time to mitigate transmission constraints. If the customer requests this information, then the MISO planning staff will provide a list of all units that affect a particular constraint with their respective distribution factors on the constraints. MISO planning staff does not perform this analysis if not requested by the customer. If the transmission customer wishes to utilize re-dispatch option then it will be disqualified to request ARRs and FTRs as documented in Module B, Section 13.5, of the Tariff.

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 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 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.
https://oasis.midwestiso.org/documents/MISO/Performance_Metrics.html

AFC procedure links:

https://oasis.midwestiso.org/documents/MISO/TP-OP-005-r5%20Available%20Transfer%20Capability%20Implementation%20Document.pdf

MISO Network and Point to Point Specification Sheets:

https://oasis.midwestiso.org/documents/miso/network_point.html

Tariff and Rate Schedules

https://www.misoenergy.org/Planning/LongTermTransmissionService/Pages/Schedules.aspx

Transmission Services webpage

https://www.misoenergy.org/Planning/LongTermTransmissionService/Pages/LongTermTransmissionService.aspx

6 Other Non-cyclical Planning Studies

6.1 Out-of-Cycle Project Review

The out-of-cycle project review is not intended to replace the MTEP study program. The expedited out-of-cycle review process is established under the Transmission Owner's Agreement as a means to address projects that cannot wait for the cyclical MTEP process. The MTEP process is intended to provide an orderly and efficient, holistic, open, and transparent expansion planning process; out-of-cycle review allows for exceptions to the preferred MTEP program. These project review guidelines exist specifically to define procedures for evaluating additions or modifications of transmission lines, transformers, other substation equipment, or load additions that have immediate analysis requirements that cannot be completed through the preferred MTEP process.

Project evaluation will still include normal review procedures, including:

- Determining if the Transmission Owner has already performed his own studies that can be used as input to MISO project review.
- Stakeholder (SPM and PS) notification of urgent project needs.
- Determining if the project is eligible for cost sharing under the Tariff.
- Screening the project for approval by ensuring that planning criteria are observed with the project in place.
- Reviewing the project (if it is eligible for cost sharing) to validate the system need for the project against applicable reliability and economic criteria.
- Confirming that the project criteria are applicable under the Tariff, and establishing it as either a Baseline Reliability Project (BRP) or Market Efficiency Project (MEP), or Other Project.
- Determining the project's applicable cost allocation under the Tariff.
- Reviewing the project for approval (if it does not meet BRP or MEP requirements) by ensuring that planning criteria are observed with the project in place.
- Reviewing needs analysis and cost allocation (if applicable) with stakeholder groups.

In order to complete out-of-cycle analyses in a reasonable time frame and in parallel with ongoing MTEP processes, the party submitting the proposed projects will be responsible for demonstrating that the project does not result in any violations of applicable planning standards, and providing this demonstration to MISO for review.

6.1.1 Entity Documentation of Need

The Transmission Owner is responsible for submitting an out-of-cycle review report that documents the system need for a proposed project. The report must include a description of system conditions causing contingency criteria violations. The report should also detail any alternatives and the rationale for selecting this project over alternative projects. MISO planning staff will confirm receipt of the report and project data. Upon receipt of the report, MISO will perform a cursory review of the submittal and, if necessary, request additional information.

6.1.2 Project Eligibility for Cost Sharing under the Tariff

The Transmission Owner's review report must clearly identify individual projects. A project must address a related group of system needs, and must be able to be operated without adversely impacting the Transmission System. MISO planning staff will confirm the existence of the system need, and the effectiveness of each project in addressing that need. MISO planning staff will then determine the eligibility for cost-sharing for each project based on applicable Tariff project costs.

6.1.3 Project Need and Effectiveness Validation

MISO will validate each project's need by analyzing relevant system conditions and contingencies without and with the proposed project. MISO will confirm that the project efficiently addresses the system need. MISO may evaluate alternative projects and discuss them with the Transmission Owner.

6.1.4 Project Criteria Violations

The Transmission Owner must complete two system study cases: the first without the proposed project and the second with the proposed project in place and operating as planned. Each case must use either an automated contingency screening analysis process such as the PSS/E ACCC, or a manual contingency analysis process. These models may include different years, seasons, and load levels. The models and contingency files must be consistent with the MTEP process, and will be chosen such that they constitute a complete representation of potential violations associated with the proposed project. The Transmission Owner must also determine if other types of study cases are necessary (i.e., stability or short circuit).

The first study case (excluding the proposed project) analyzes pre-contingency and post-contingency conditions, and should show violations of NERC criteria, such as overloaded facilities and over and under voltages. Any violations will be flagged and listed in the contingency analysis output as a pre-existing condition. The second case (including the proposed project) analyzes the same pre-contingency and post-contingency conditions as the first, and again identifies any violations of NERC criteria. The results of the first and second study cases are compared to each other to determine the relative impact of the proposed project on the system. Any new criteria violations on any MISO member or neighboring systems resulting from the project must be documented. MISO will review the Transmission Owner's contingency results. MISO planning staff may accept this analysis or, if necessary, perform independent validation.

6.1.5 Project Type Categorization for MTEP

MISO will review the project and categorize it so that it can be included in the MTEP Database. This categorization process also determines if the project is eligible for the Tariff cost-sharing process, as described in Section 8.

6.1.6 Project Cost Allocation & Stakeholder Review

MISO will determine the cost allocation applicable for each project once the current MTEP cycle is completed. Prior to the MTEP cycle, MISO will inform the Transmission Owner regarding the applicable cost allocation methodology per Attachment FF of the Tariff (*e.g.,* as a percentage postage stamp and percentage sub-regional LODF). If the project is subject to regional cost sharing per Attachment FF, the project will be presented to stakeholders for review prior to going to the Transmission Provider Board for approval.

6.1.7 Project Approval Status

MISO will inform the Transmission Owner of each project's approval status as well as its categorization for cost allocation. The Transmission Owner should review the project approval status and contact MISO planning staff with any questions or comments.

6.2 System Support Resource (SSR) Studies to Evaluate Unit De-commissioning

6.2.1 Introduction

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 decommissioned, placed into extended reserve shutdown or disconnected from the MISO region."

The SSR procedure includes the following steps:

1. Market Participant (MP) who is planning to retire or mothball his owning/operating Generation Resource or SCU located in MISO region, must submit a completed Attachment Y to MISO at least twenty-six weeks prior to taking such steps;
2. A detailed reliability study will be performed for the SSR study. Any valid reliability violations will be cited if they are caused by the retirement of the generator/SCU;
3. Before a Generation Resource or SCU is justified for SSR status, other feasible alternatives such as generation re-dispatch, system reconfiguration, transmission project acceleration, new transmission project, new generator resource or SCU installation, remedial action plans, or Demand Side Management (DSM) will be assessed. Only when there is no identified applicable alternative which is more economical than the operation of SSR unit, MISO and the Market Participant shall enter into an SSR Agreement with Attachment Y-1. Otherwise, the Generation Resource or SCU will be approved for retirement;
4. The SSR unit will be operated based on the established terms in Attachment Y-1, and costs to compensate an SSR units will be allocated to the Load Serving Entity that benefits from the operation of the SSR unit, which is determined by the SSR study; and
5. MISO shall annually review the reliability requirements and determine whether the SSR agreements should be extended.

MISO will evaluate the performance of the Transmission System against applicable reliability standards/criteria to determine the SSR status when the Market Participant owning or operating such a facility submits a completed Attachment Y to the Tariff. Before SSR status is justified, other alternatives should also be considered to determine the most economical and feasible solution. These alternatives include generation re-dispatch, system reconfiguration, transmission additions, new generator resource or SCU installation, remedial action plans, or demand response solutions.

6.2.2 Power Flow Model Preparation

At least two sets of models will be prepared for the SSR study: the near-term model which represents the year the generation resource or SCU is to be retired, and the mid-term model which typically represents the five-year ahead outlook. The models are based on contractual dispatch, with firm transactions appropriately modeled and Network Resources economically dispatched in each balancing area. Normally, the mid-term model is developed from the latest MTEP model, and the near-term model is developed from the latest series of MISO model. Both models are updated with latest updates and corrections. Typically, summer peak model will be chosen for the SSR study. In areas where other situations are deemed necessary, the models which represent these situations will be picked as additions.

For each model, two scenarios will be created which represent the "before" and "after" generator/SCU retirement states. The models which represent these two scenarios are created in the following steps:

Step 1: The "after" retirement model should be created first as follows:

a) Using a model representing the year of interest, create a balancing area, merit order generator dispatch that excludes the unit(s) to be retired (i.e. the unit(s) will be off-line).
b) The "after" retirement model is now complete.

Step 2: The "before" retirement model should be created from the "after" retirement model since the reliability violation difference between these models are to be compared.

a) Renumber the control area of any on-line generation in the balancing area of interest that is located at the same physical plant site or the electrically equivalent site as the to-be-retired units. This step is necessary to avoid re-dispatching these units in the next step.
b) Scale down the generation in the balancing area of interest equal to the "to-be-retired" unit(s) amount.
c) All generators whose control area was renumbered in step 2a) above should now be moved back into the control area of interest.

d) Turn on the unit(s) to be retired.
e) Check swing machine in the event that a large unit retirement results in a substantial control area loss change.
f) The "before" retirement model is now complete.

6.2.3 Reliability Evaluation

System Intact (Category A) and single-element contingencies (Category B) will be considered in the evaluation, which are consistent with NERC Planning Standards I.A. Category B includes any single transformer, generator, or transmission line outage. In addition, significant multiple-element contingencies consistent with NERC Category C will be reviewed.

NERC Transmission Planning Standards TPL-001, TPL-002, and TPL-003 effective April 1, 2005 will be applied to test the system. In performing the SSR study, Regional, State, and MISO Member (Local) planning criteria will be respected. In addition to NERC Standards, load deliverability will be tested in areas with potential load deliverable deficiency. A 1 day in 10 year LOLE criteria will be applied.

The reliability evaluation for the SSR study is described below:

- All 69 kV and above facilities in the balancing area where the candidate retired unit is located are monitored. 100 kV and above facilities in other neighboring balancing areas (with direct ties) are also monitored.
- Branch loading is tested against its normal thermal rating for Category A condition (system intact), and against its emergency thermal rating for Category B and C contingencies.
- Steady state bus voltage criteria specified in "MISO Voltage and Reactive Management Process Phase I - Effective 7/1/04" are adopted, with respect to a MISO Members' (Local) voltage 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 system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the “after” retirement scenario is equal to or greater than:
  a) 5% of the “to-be-retired” unit(s) MW amount (i.e. 5% PTDF) for a “base” violation compared with the “before” retirement scenario; or
  b) 3% of the “to-be-retired” unit(s) amount (i.e. 3% OTDF) for a “contingency” violation compared with the “before” retirement scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the “before” retirement voltage calculation.
- Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, or load shedding will be considered if applicable.
- In areas with potential load deliverable deficiency, load deliverability study will be performed. The criteria of 1 day in 10 year LOLE will be applied.
- Angle/voltage stability studies will be performed if necessary.

6.2.4 Alternatives Evaluation

Before a Generation Resource or SCU is justified for SSR status, other feasible alternatives such as generation redispatch, system reconfiguration, transmission project acceleration, new transmission project, new generator resource or SCU installation, remedial action plans, or Demand Side Management (DSM) will be assessed. Only when there is no identified applicable alternative which is more economical than the operation of SSR unit, MISO and the Market Participant shall enter into an SSR Agreement with Attachment Y-1. Otherwise, the Generation Resource or SCU will be approved for retirement.

6.2.5 Report Writing

After the SSR study is finished, a detailed study report will be drafted and archived. A letter with final SSR study decision will be mailed to the Market Participant who is applying for the retirement or mothball of Generation Resource or SCU.

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

Transmission expansion projects that serve a documented need for baseline reliability are eligible for MTEP cost-sharing if they: 1) have a total cost of $5 million or more; or 2) have a project cost below $ 5 million, but a total cost that is 5% or more of the Transmission Owner's net plant as established according to Attachment O.

All costs for Baseline Reliability expansion projects with a rated voltage of 100kV through 344kV are allocated to Transmission Customers in designated sub-regional pricing zones. The sub-regions and pricing zones are determined on a case-by-case basis using the Line Outage Distribution Factor (LODF) process described in Appendix J of this BPM. With this process, Transmission Customers that benefit from the expansion project are allocated costs proportional to the benefit received.

For Baseline Reliability expansion projects with a rated voltage of 345kV or higher, twenty percent (20%) of the costs are allocated to all pricing zones. The remaining 80% of project costs are allocated sub-regionally to all Transmission Customers within designated pricing zones. As before, the sub-regions and pricing zones are determined on a case-by-case basis using the LODF process described in Appendix J of this BPM. The 20% - 80% split on project costs reflects a MISO planning staff assessment that projects rated 345kV or higher improve system reliability and power flow characteristics for all Transmission Customers across the MISO footprint.

Line Outage Distribution Factor (LODF)

As described above, 20% of approved Project Costs are allocated on a system-wide basis to all Transmission Customers. The remaining 80% of Project Costs are allocated to Transmission Customers in designated pricing zones on a case-by-case basis using the LODF method.

The LODF method first determines the impact of a new facility planned as part of an expansion project on other, existing components for a defined region. MISO planning staff uses the PSS/E MUST software to estimate power flow under two scenarios: the first includes the proposed new facility, and the second excludes the proposed facility. The LODF is then calculated as the absolute value of the estimated percentage change in power flow over existing components between these two scenarios. Where a project consists of multiple facilities, each one is tested for its effect on the existing system.

Equation 8.1 - 1

$$LODF = Abs\left({(PF_2 - PF_1)}/{PF_2} \right)$$

Where: PF_2 = Estimated power flow on existing facilities excluding the expansion project
PF_1 = Estimated power flow on existing facilities including the expansion project

As an example, consider an existing circuit where the estimated power flow under given operating conditions is 100 MW. A proposed expansion project adds facilities such that the estimated power flow on the existing circuit is reduced to 90 MW under identical operating conditions. The LODF for the existing circuit is 10%, as calculated using Equation 8.1-1 as follows: (100 MW – 90 MW)/100 MW = 10%.

The MUST software calculates estimated power flow "with and without" 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 1% (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 Owners 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.

The additional criteria used in the calculation of cost allocations for Baseline Reliability Projects are described in Appendix J of this BPM.

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 100 percent of the costs of Network Upgrades rated below 345 kV and 90 percent of the costs of Network Upgrades rated at 345 kV and above (with the remaining 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 345kV or above, has total project costs of $5 million or more, and can demonstrate regional benefit metric, multiple future scenarios, and multi-year analysis as described in Sections 8.4.1 and 8.4.2 below.

Twenty percent (20%) of the cost for a Market Efficiency Project is allocated to all Transmission Customers through a system-wide rate. The remaining 80% of the project cost is allocated to all Transmission Customers in each of MISO's seven Local Resources Zones, see Attachment WW of the Tariff. The cost allocated to each of these Local Resource Zones is based on the relative benefit each receives from the project, as determined by the economic benefit analysis process described in Sections 8.4.1 and 8.4.2 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 Local Resource Zone from being allocated costs where they may not benefit from the project. Local Resource Zones that are not shown to receive net benefits from the Market Efficiency Project will be excluded from the allocation of the 80% component of 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 Metric

The criteria to determine whether a project should be included as a Market Efficiency Project is based on multiple future scenarios and multi-year analysis guided by input from all stakeholders. The benefit metric will use a weighted futures, no loss (WFNL) metric to analyze the anticipated annual economic benefits of construction of a proposed Market Efficiency Project to Transmission Customers in each of the Local Resource Zones based upon adjusted production costs (APC). APC savings will be calculated as the difference in total production cost of the resources in each Local Resource Zone adjusted for import costs and export revenues with and without the proposed Market Efficiency Project as part of the Transmission System. The WFNL metric for each Local Resource Zone will be calculated using the weighted APC savings determined for each future scenario included in the analysis.

Adjusted Production Cost savings are estimated by modeling the production cost of the base case and alternative transmission system plans, and comparing each plan to several possible Future economic or operating scenarios. An example of this method is presented graphically in

Figures 8.4-1 and 8.4-2, as decision trees. In these Figures, several Futures are presented showing combinations of fuel price escalation rates and load forecast projections. There are three fuel price escalation possibilities (low, trend, and high), along with three load requirement forecasts (also low, trend, and high). The estimated probability of each possible condition is shown, and the joint probability for each resulting Future (a combination of two possibilities) is calculated.

Figure 8.4-1 presents example results for the base transmission plan production cost. Each Future has an associated total production cost and joint probability, and the expected cost (weighted by joint probability) is $536 million. Figure 8.4-2 presents a similar analysis, using an alternative transmission expansion plan. In this scenario, the modeling yields an expected cost of $526 million, using the same Futures as used for the base case. Comparing these two cases indicates that the estimated production cost savings from the alternative transmission expansion plan is $10 million.

While this example considers uncertainties around two critical inputs (fuel cost escalation and load forecast), in practice MISO planning staff may consider uncertainties for several variables, such as fuel prices, load forecasts, cost escalation rates, unit outage rates, environmental compliance costs, and unit operating constraints.

Equation 8.4-1

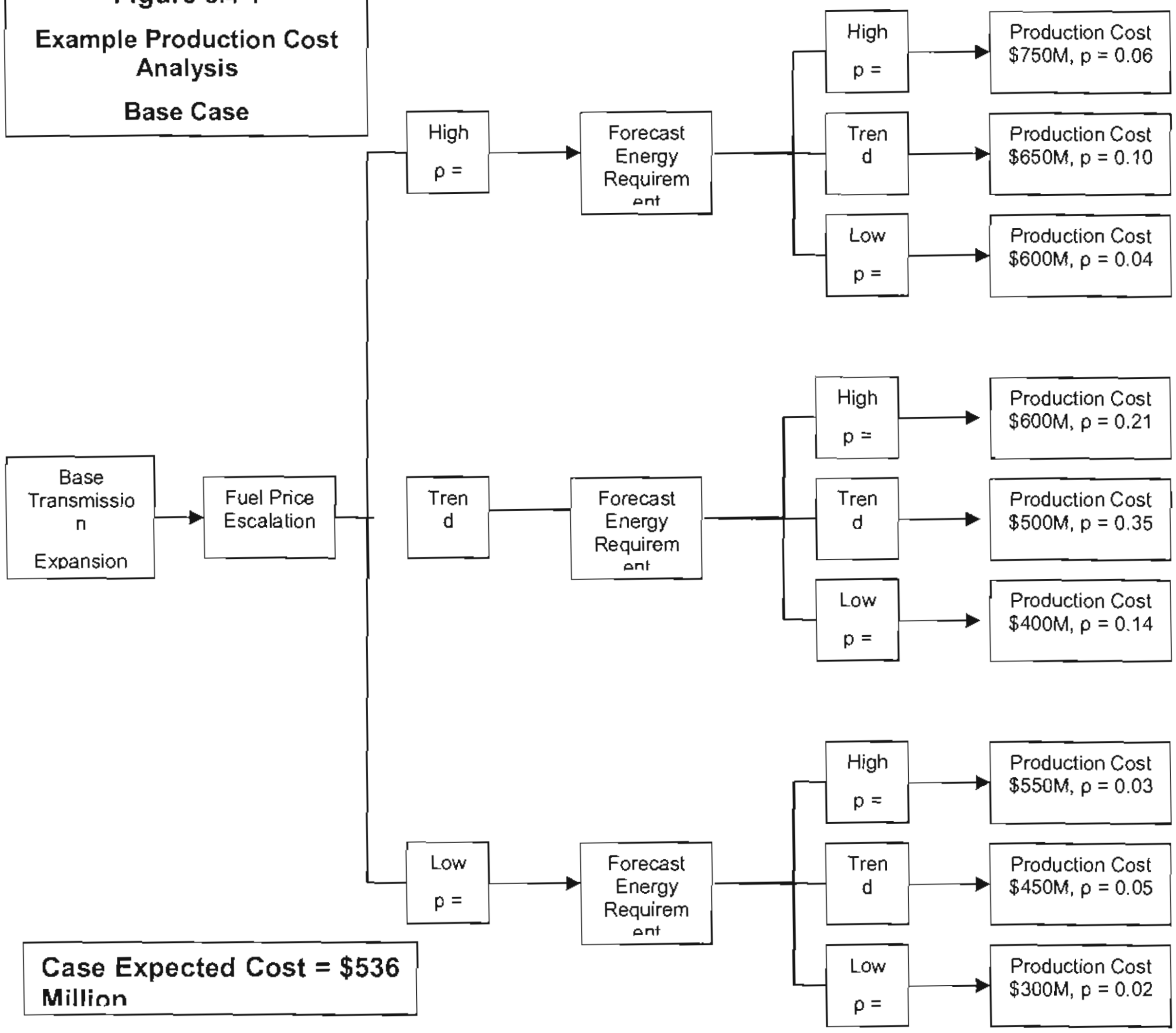
$$WGNL = (70\%\,APC + 30\%\,Load\,LMP)$$

Where: APC = Estimated savings from Adjusted Production Costs
Load LMP = Estimated savings on Locational Marginal Price at affected power delivery nodes.

Figure 8.4-1

Example Production Cost Analysis

Base Case

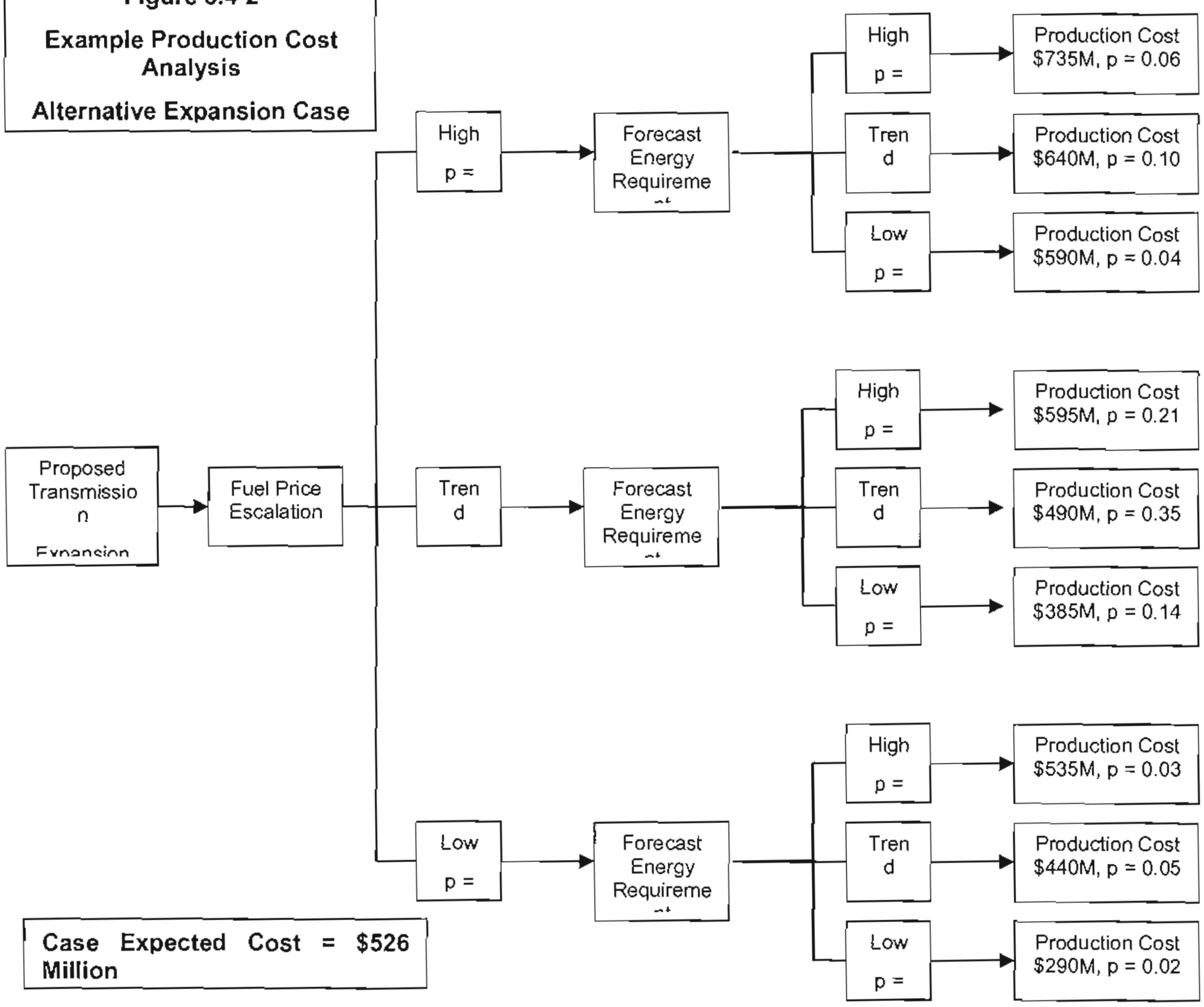


Case Expected Cost = $536 Million

Figure 8.4-2

Example Production Cost Analysis

Alternative Expansion Case



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 WFNL values for each Local Resource Zone. The total project benefit will be determined by calculating the present value of annual benefits for the multiple future scenarios and multi-year evaluations.

The costs applied in the benefit to cost ratio 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.

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 Owners 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 8.5.1, and satisfy all of the conditions listed in Section 8.5.2. 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 document. 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 8.5.3 of this document.

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 document, 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 5% 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 Entrant (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 8.5.2 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 8.5.2 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 percent (100%) 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 8.5.5.1 of this BPM. These annual revenue requirements will be recovered through a MVP Usage Charge which is described in more detail in the Market Settlements BPM. Revenues collected through this charge will be distributed to the Transmission Owners in accordance with the ISO agreement.

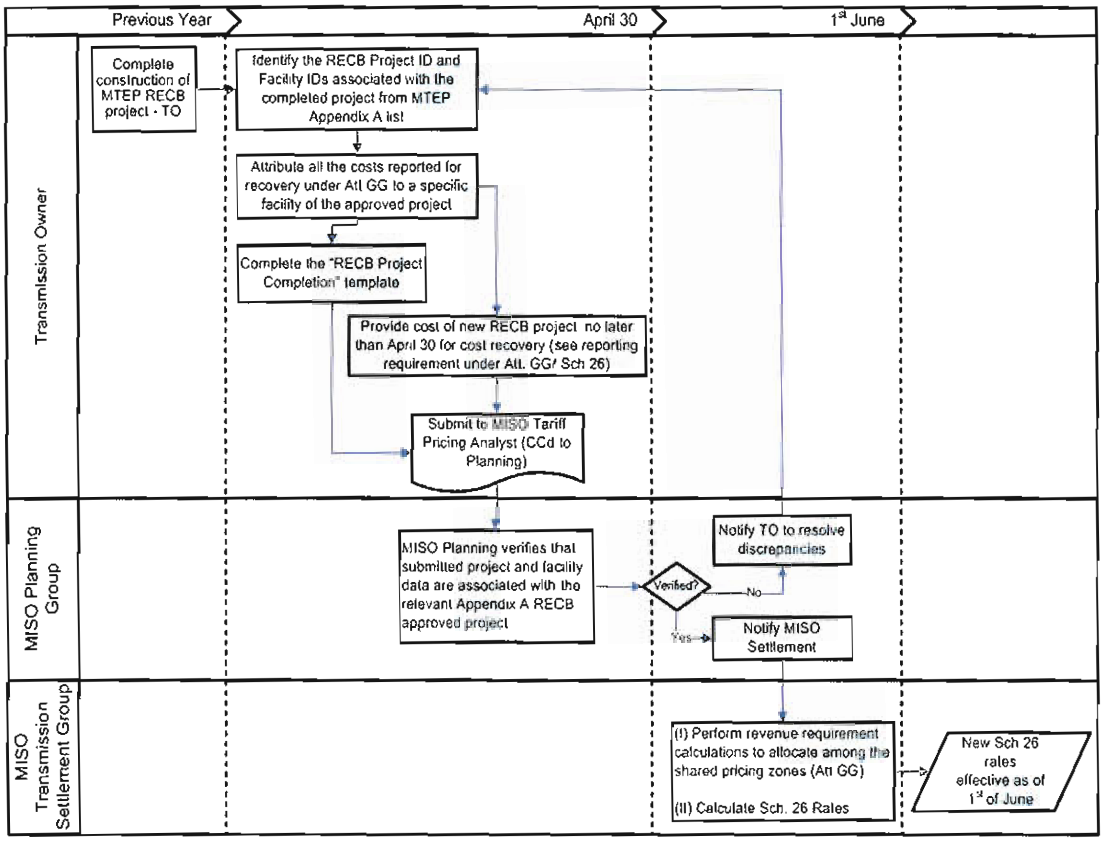
7.6 Project Completion Reporting Guidelines – for Cost Shared Projects

Transmission Owners shall report the MTEP approved cost shared projects (i.e., BRP, GIP, MEP 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 and MEP) and Attachment MM (MVP) revenue requirement and rates calculations. Also, the information will be 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. Fig. 8.6-1 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 (https://www.misoenergy.org/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 Owners with FERC approval for recovery of CWIP costs.

Fig 7.6-1: Process Flow for Reporting MTEP Cost Shared Project Costs for Recovery under Att. GG



Note: (1) For certain Transmission Owners (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.

Appendix A:

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Appendix B: MISO TSR Planning Guideline #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 Owners, or Third Parties when reporting results of an SIS in order to provide consistency in the reporting of results of such studies.

REPORT OUTLINE

The SIS report shall include the following information:

Executive Summary
This section lists:

1) Type of service requested
2) Whether or not service can be granted at this time
    i. Profile of service, if applicable
    ii. List of milestones for the profile
    iii. List (or point to a list) of transmission system constraints
    iv. Cost to resolve the constraints to service
    v. 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.

Introduction
A brief description of the background, purpose, and objectives of the study

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: MISO TSR Planning Guideline #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 Owners, 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:

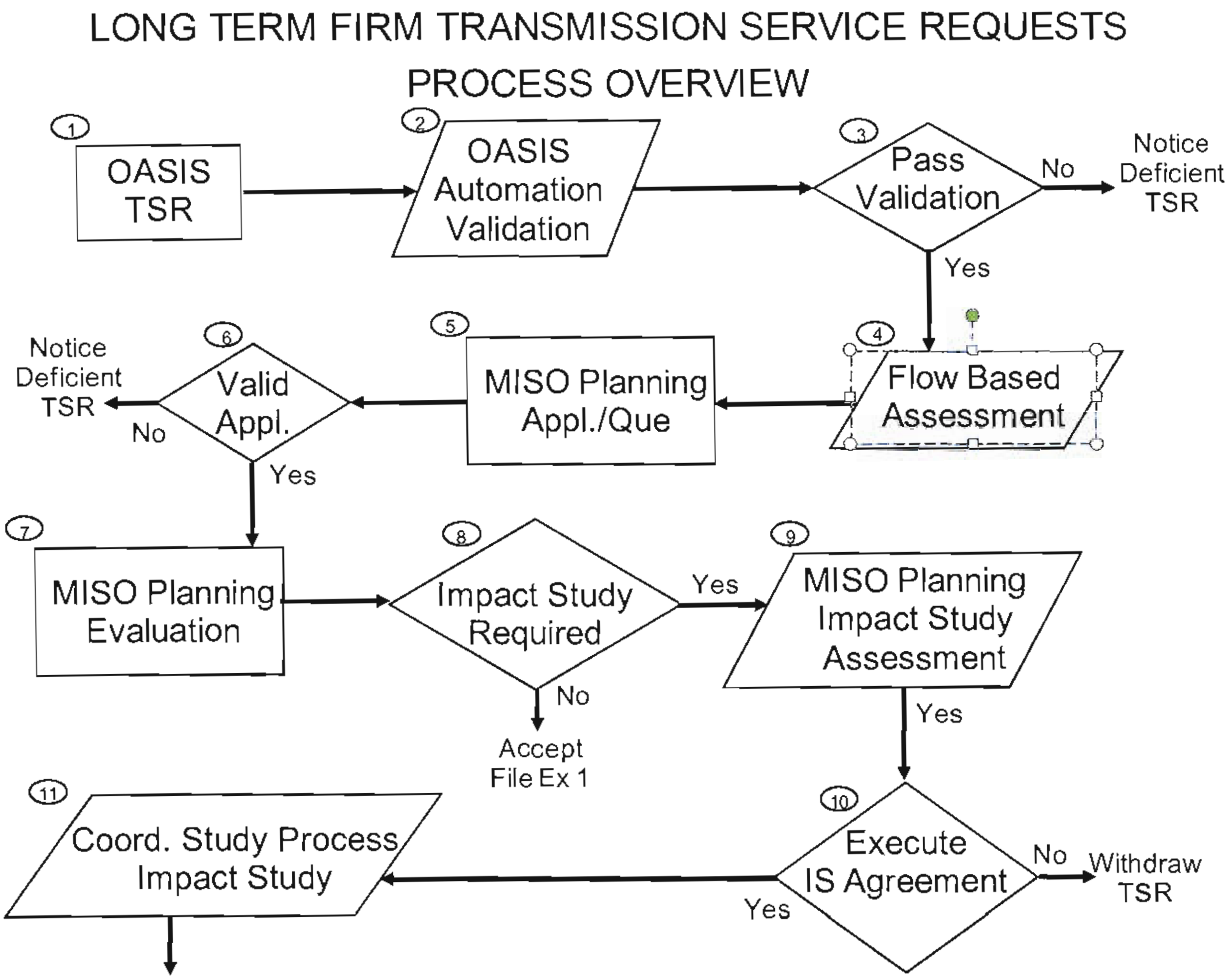
Introduction
A brief description of the background, purpose, and objectives of the study

Description of Request
The OASIS request information identifying the transaction

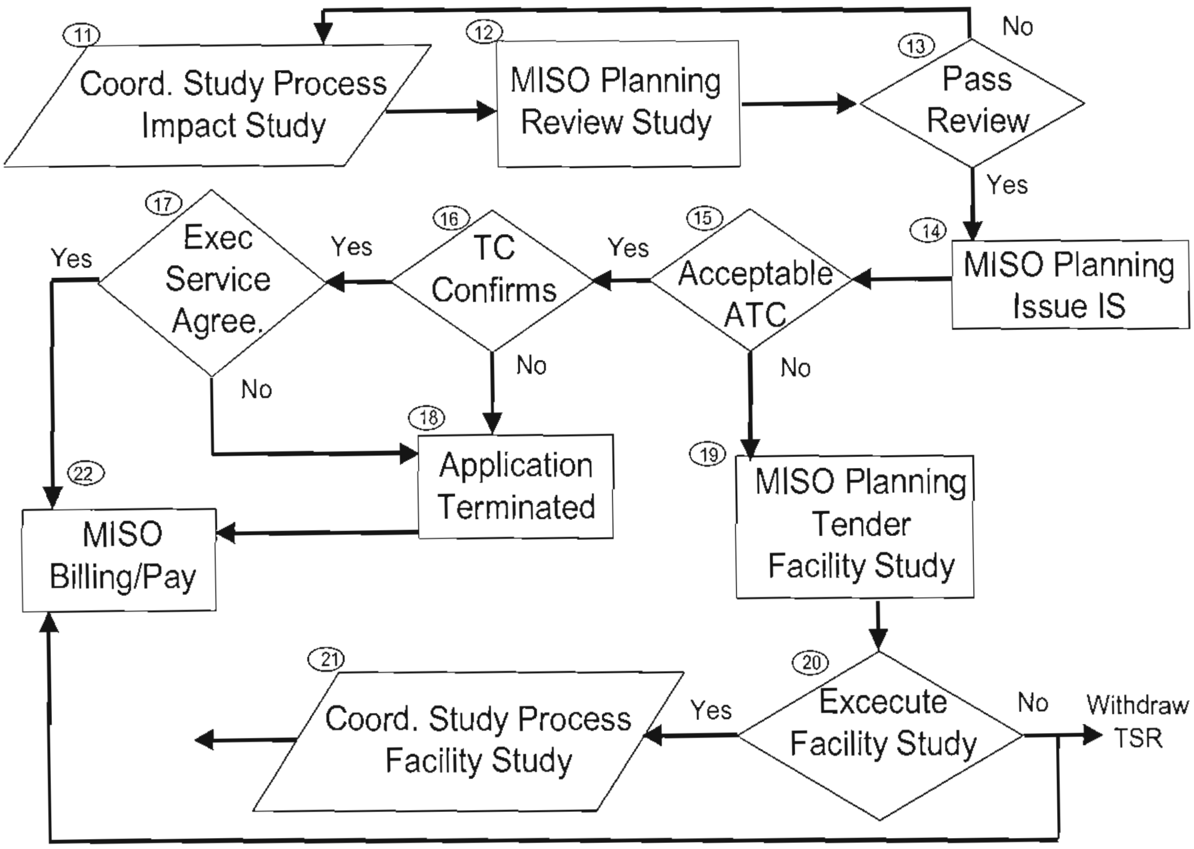
Criteria, Methodology, and Assumptions
A detailed statement of criteria used, including any specific Regional or local criteria applied. The study scope and a description of how the study was conducted, including the cases, scenarios, critical assumptions, and modeling of the new or modified facilities.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



LONG TERM FIRM TRANSMISSION SERVICE REQUESTS
PROCESS OVERVIEW



Appendix J: Implementation Rules for LODF Calculation and Qualifying System Conditions for Cost Sharing of Baseline Reliability Projects otherwise eligible for Cost Allocation consistent with Attachment FF to the Tariff

The following LODF calculation rules will be applied for Cost Allocation of Baseline Reliability Projects.

J.1 General LODF Methodology and Thresholds

- Use RECB developed "Sum of Absolute value of LODF-Mile" method to develop sub-regional cost allocation percent. LODF values generally determined using MUST LODF function by setting a contingency (outage of the project) and monitored branch lists, or equivalent method. All MISO Transmission Facilities are monitored.
- LODF cutoff rate: 1% (if a monitored branch does not respond by 1% of the project line flow, its impact is ignored)
- Mileage: Line length 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
- Tie-lines: Percent ownership as reported by Transmission Owners. Otherwise default owner is non-metered bus terminal in model.
- 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 J.4 below)

J.2 Models and Applicable Topology

- The current MTEP planning horizon model is used for all project LODF calculations. For example, if a 2011 model is being used for MTEP, and a project is first identified as a required Baseline Reliability Project in that MTEP process, the 2011 model will be used even though the project may have a 2009 service date. This avoids the need to develop many different models for LODF determination, and in any event, such a project will have the LODF calculated under the 2011 topology eventually.

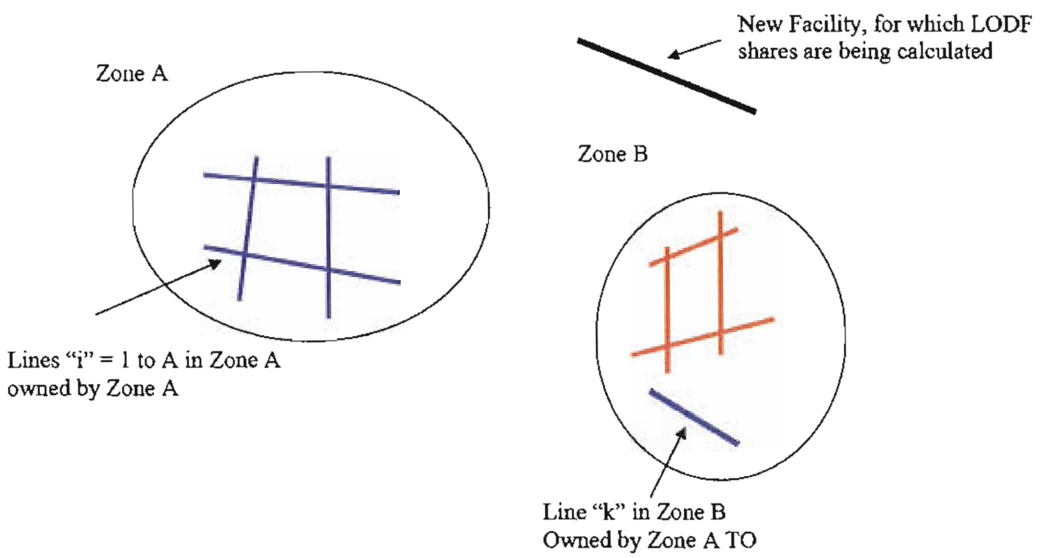
- For each project evaluated, all other Planned and Proposed projects with service dates on or before the MTEP planning horizon year are in the model.
- Both Planned and Proposed Projects that are required to address identified needs will be included in the model. Proposed Projects are included because it is assumed that Proposed Projects or some form of alternative that is not currently known will be required. Proposed Projects to be included in the model are those for which it has been shown that the proposed Project or some alternative is needed to resolve a reliability issue.
- 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.3 Project Specific Methodology

- Only Planned Projects that are Baseline Reliability Projects will be evaluated for cost allocation, although these projects will be evaluated on a model that includes currently identified Planned and Proposed Projects as above. This will avoid requesting MISO to "test the cost allocation waters" as a basis for determining if a Proposed project should be classified as a Planned project to go forward. This determination is better made on the cost effectiveness of the project itself.
- A reconductored line will 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.

- New capital investments for replacements, or rebuilds due to aging equipment rehabilitation or replacement will not be cost shared.
- Allocations of costs of 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.
- Cost of terminal upgrades including bus sections, switches, circuit breakers (CB), 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 LODF for upgrades to existing circuit breakers or other interrupting devices that are needed due to increased interrupting duty or continuous loading capability will be defined as 1.0 for all branches in the pricing zone where the circuit breaker is installed, and 0.0 for all other branches. This will result in the costs of these circuit breakers being allocated based on LODF to be 100% local.
- 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 be shared 80% Local, 20% Postage Stamp for shunts connected to 345 kV and above (LODF = 1 for local branches, 0 for others), and 100% local for below 345 kV.
- 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.
- Except for new transformer installations with high side voltages of 345 kV or higher and low side voltages of 344 kV or lower, 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 20% 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.



$$\text{Share}_{\text{Zone B}} = \frac{\sum^{B} \text{LODF}_{i} + \text{LODF}_{k}}{\text{LODF}_{sys}}$$

J.4 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.

J.5 Qualifying System Conditions for Cost Sharing of Baseline Reliability Projects Otherwise Eligible for Cost sharing Under the Tariff

[THIS SECTION RESERVED FOR SPECIFICATIONS TO BE ESTABLISHED BY PS FOR BRP DRIVEN BY SUCH THINGS AS

- NERC C3 CRITERIA
- LOLE ANALYSIS
- NERC PLANNED OUTAGE CRITERIA
- NERC CRITICAL SYSTEM CONDITIONS CRITERIA IN GENERAL
- ETC]

J.5.1 Cost Sharing Treatment of Baseline Reliability Projects Justified Based on NERC Category C3[2] Contingencies

Under Attachment FF to the TEMT, costs of Baseline Reliability Projects included in the MTEP and for which (1) the Network Upgrade has a Project Cost of $5 million or more or (2) the Network Upgrade has a Project Cost of under $5 million and is five percent (5 %) or more of the Transmission Owner's net plant as established in Attachment O of the Tariff, shall be subject to the cost sharing provisions of Attachment FF. Attachment FF defines Baseline Reliability Projects as "Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region."

For events defined by NERC as Category C events, ensuring compliance with national ERO reliability standards requires under the NERC TPL standards, the following[3]:

> "The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard."

Category C3 events are defined in the TPL standard as events resulting in the loss of two or more (multiple) elements, and more specifically as a:

> SLG or 3Ø Fault (on a generator, transmission circuit, or transformer), with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing.

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[2] NERC Category C3 is a designation in the Approved Version 0 of the NERC Standards TPL-003-0.
[3] NERC Standard TPL-003-0 Requirement R1.

Table I of this standard further describes the permissible system performance for these C3 events as requiring:

- System Stable and both Thermal and Voltage Limits within Applicable Rating
- No Cascading Outages
- Planned/controlled Loss of Demand or Curtailed Firm Transfers is permitted. (This performance requirement is footnoted as saying that "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems."

The combined result of these requirements under the tariff, and under the NERC TPL standards, is that for Category C3 events such as the sequential (non-simultaneous) loss of a generator and a line or transformer, the loss of two (2) lines or two (2) transformers, or of a line and a transformer, compliance with the standard permits the controlled shedding of load, tripping of generators, or redispatch of resources resulting in the curtailment of firm transfers, if required in order to prevent instability or cascading outages.

The following business practices are not intended to define planning criteria, to judge the appropriateness of any transmission system expansion proposed for implementation as a means to address system performance requirements for NERC Category C3 events, or to establish new tariff eligibility requirements for cost sharing of Baseline Reliability Projects. Rather, these practices define the decisions to be made by MISO planning staff in determining which reliability projects will be considered by MISO to meet the tariff defined characteristics of a Baseline Reliability Project of being "required to ensure that the Transmission System is in compliance with" the performance requirements for NERC Category C3 events.

J.5.1.1: System Reconfiguration and Redispatch Evaluation for Category C3 Events

System reconfiguration will be considered as an acceptable system adjustment following loss of the first element of a Category C3 Event, and prior to the loss of the second element, in order to maintain system loadings and voltages within applicable ratings following the second event. System reconfiguration includes supervisory controlled or automatic operation of bus-tie circuit breakers, switching of transmission lines, transformers, series or shunt reactive devices, or adjustment of controllable elements such as LTC transformers, phase angle regulators, HVDV lines, generator voltage regulators or other such devices. System reconfiguration must be such as to maintain system loadings and voltages within applicable ratings for any subsequent facility Category B outage in addition to the originally contemplated Category B event.

Redispatch will also be considered as an acceptable system adjustment to be made following the outage of the first element of a Category C3 Event, and prior to the outage of the second element. It is assumed, unless demonstrated to the contrary, that the expected value of cost of such a reliable-redispatch following the outage of the first element would be very low and would always provide an economically superior solution to a comparable Network Upgrade. This is because of the lower probability of being in the post single contingency outage state coupled with the system load and dispatch conditions resulting in reliability violations anticipated for the second outage. To ensure that the generation redispatch is an economically superior solution when compared with a network upgrade, the study must demonstrate that the redispatch is a reliable alternative to mitigate the NERC-C3 contingent constraint. The following criteria have been developed to better define a "reliable" redispatch.

1. Due to the uncertainty that any existing generating unit will continue to be a viable unit over the planning horizon, redispatch evaluation must demonstrate that there are sufficient generating units that are available to provide the incremental capacity necessary to maintain loadings and voltages within applicable ratings, without reliance on any single unit. In general, all Network Resources (NR's) and Energy Resources (ER's) are candidates for redispatch as their output can be reduced to minimum levels or turned off, including wind plants. If generating units are to be decommited, the reliability impacts of the generation change, including a voltage analysis, would need to be evaluated. The participating generators must have a distribution factor of greater than 3%. Distribution factor is defined as the sensitivity of the generating unit to the thermal constraint resulting from the C3 contingent event. Lower than 3% distribution factor is indicative of an inefficient redispatch.
2. No more than 10 individual conventional fuel units or individual wind plants shall be used in any redispatch scenario.

3. No more than 1000 MW shall be used to increment and no more than 1000 MW shall be used to decrement in any redispatch scenario. Therefore, no more than a total amount of 2000 MW of generation shift shall be allowed to redispatch around a constraint.
4. Non dispatchable units will be excluded from redispatch calculations. Nuclear generating units will also be excluded unless otherwise required by their operating agreements. In general, feedback from Stakeholders will be requested regarding the reasonableness of units to be considered in the redispatch options prior to commencement of the annual MTEP reliability assessments.
5. After redispatch the loadings on all facilities should be within applicable ratings per the Transmission Owner facility rating methodology consistent with NERC FAC-008 standard.
6. Consideration of external generation in redispatch calculations:
    a. If the identified C3 driven constraint is a PJM-MISO reciprocal coordinated flowgate (RCF) eligible for market to market redispatch, PJM units will be included in the redispatch.
    b. If the identified C3 driven constraint is not currently a PJM-MISO reciprocal coordinated flowgate (RCF), the flowgate would be recommended for RCF qualification study. If not eligible, PJM units will not be included in the redispatch.
    c. Generators considered within existing operating guides, procedures and Special Protection Schemes (SPS) will be included as applicable to the overloaded facilities.
    d. No other non-MISO units along seams will be used in redispatch.

To the extent that such reliable-redispatch is shown to be available using the applicable MISO MTEP planning model to maintain system loadings and voltages within applicable ratings following the second outage, of a Category C3 event, MISO business practice will be to not accept a Network Upgrade proposed as a Baseline Reliability Project eligible for cost sharing.

J.5.1.2: Load Shedding Limits after which Baseline Reliability Projects are Supported for Cost Sharing

Because the NERC TPL standards do not state a limit as to the amount of load shedding that is permissible in order to maintain system stability and to avoid cascading outages following a Category C3 event, MISO business practice will be to accept as a Baseline Reliability Project eligible for cost sharing (subject to passing the project cost and voltage thresholds of Attachment FF), a Network Upgrade that is needed to avoid any of the following, after the redispatch and reconfiguration options of Section I.5.1.1 have been exhausted:

1. Controlled Load shedding of 100 MW or more implemented as an operating guide prior to the second element outage and as demonstrated to be necessary using the applicable MISO MTEP planning model, to avoid instability or an unbounded cascading following the second element outage.
2. Bounded thermal cascading outages resulting in 300 MW or more of load as a consequence of sequential element trips, as demonstrated to occur using the applicable MISO MTEP planning model, and the thermal cascading outage testing method of Section 4.3.7 A. of this BPM.
3. Loss of electric service to more than 50,000 customers as estimated by the Transmission Owner with agreement from the affected Local Distribution Company, and as a consequence of sequential element trips, as demonstrated to occur using the applicable MISO MTEP planning model, and the thermal cascading outage testing method of Section 4.3.7 A. of this BPM.

Condition 1, above has a lower load loss amount than condition 2, because condition 1 would shed this load after a single contingency in anticipation that the second contingency would result in an unbounded cascading event. Condition 2 would result in the larger amount of lost load only in the event that the second contingency actually occurred, and therefore would occur with much less frequency.

Condition 3 reflects that in lower average customer peak demand areas, 50,000 customers may represent less than 300 MW of load, but would represent a similarly severe customer outage event.

The above conditions are based on the threshold reporting requirements established for emergency events by the Department of Energy (DOE) and reportable on form OE-417. See http://www.oe.netl.doe.gov/oe417.aspx

According to the DOE OE-417 establishes mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form OE-417 to meet its overall national security and Federal Emergency Management Agency's National Response Framework responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. The data also may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

J.5.2 Cost Sharing Treatment of Baseline Reliability Projects Justified Based on NERC Category C1, C2 or C5 Contingencies

Category C1, C2 and C5 events are also defined in the TPL standard as events resulting in the loss of two or more (multiple) elements, and more specifically as a:

C1: SLG or 3Ø Fault on Bus Section, with Normal Clearing.
C2: SLG or 3Ø Fault on Breaker (Failure or Internal Fault), with Normal Clearing.
C5: Any two circuits of a multiple circuit towerline, with Normal Clearing.

Table I of this standard further describes the permissible system performance for these Category C events as requiring:

- System Stable and both Thermal and Voltage Limits within Applicable Rating

The distinction between C3 and C1, C2 or C5 events is that while all of these events result in loss of two or more elements, C1, C2 and C5 loss of elements result from a single initiating event. Thus while planned or controlled system reconfiguration such as generation redispatch and load curtailments are permitted, implementation is required before applicable ratings are exceeded. In other words, system adjustments need to be implemented to maintain loadings within ratings following the initiating event.

To the extent the aforementioned system adjustments can be implemented post contingency without exceeding applicable emergency condition ratings, the same thresholds for system adjustments included within Section J.5.1.2 apply for purposes of Cost Sharing.

J.5.3 Treatment of Baseline Reliability Projects justified based on NERC Category B contingencies during Maintenance Periods

Limiting planning studies to only include known outages of generation or transmission with duration of at least six months may have a detrimental impact to reliability of the bulk electric system. A properly planned transmission system is one that has been planned to ensure that the removal of any BES facility for maintenance purposes can be accomplished without the need to deny or re-schedule such maintenance in order to prevent loss of firm load for the next single contingency as reasonable to plan for.

It is important to differentiate between planning for a scheduled outage and planning for an unscheduled but potential planned outage, but that both must be planned for. A scheduled outage refers to a specific known planned outage that has already been scheduled, and if scheduled in the planning horizon, naturally becomes part of the base case for the duration scheduled. Planning for unscheduled planned outages refers to the ability of the system to maintain sufficient levels of robustness to accommodate any future planned outage that might be scheduled during light load or shoulder peak conditions (when necessary maintenance is routinely performed) and still meet the TPL standards given this outage. All BES facilities need to be removed from service on a routine basis over a period of years so that over the 10 year planning horizon to which the TPL standards are applicable it is impossible to know which facilities may need to be on scheduled outage for maintenance in any given year. If the planning for the system over the 10 year planning horizon merely assumes that in the spring and fall heavy maintenance periods none of these conditions will occur, or that they can be accommodated with reasonable expectations for the forced contingencies of the TPL table, the outage scheduling in real time could get increasingly difficult to perform. Opportunities for coordinating the scheduling of all maintenance needs in real time will be reduced over time causing the indefinite deferral of necessary maintenance with consequences to the safety and reliability of the grid.

For the above reasons, MISO will analyze maintenance outages in off-peak cases representative of high maintenance periods like the spring and fall seasons, consider generation redispatch in addition to other feasible operating measures such as system reconfigurations. Additionally, in situations where firm load curtailment may be needed to alleviate identified reliability issues driven by maintenance outage in conjunction with next single contingent event, MISO may plan non-cost shared reliability network upgrades in collaboration with its Transmission Owners.

Appendix K: Notes to Disturbance-Performance

Notes:

1. *The MAPP Disturbance-Performance Table applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to 30 minutes);*
2. *The following summarizes the automatic and manual readjustments that are permissible for all NERC category B disturbances.*
   A. *Generation Adjustments (Spinning and Non-Spinning Operating Reserve) – Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation changes is limited to that amount that can be accomplished within the Readjustment period. Due consideration will be given to start up time and ramp rates of the units.*
   B. *Capacitor and reactor switching – The number of capacitors and reactors, which may be switched, is limited to those which could be switched during readjustment period.*
   C. *This includes those capacitors and reactors that would be switched by automatic control with the same period.*
   D. *Adjustment of Load Tap Changers (LTC's) to the extent possible within the Readjustment period. This includes both LTC's which would automatically adjust and those under operator control which could be adjusted within the Readjustment period.*
   E. *Adjustment of phase shifters to the extent possible within the readjustment period. Agreement must be obtained from the owner(s).*
   F. *Adjustment of the amount of the flow the HVDC can be increased or decreased within the readjustment period.*

G. *Generation Rejection – Generation may be rejected in one of two methods; tripping the generating unit or tripping generation supported tie lines. For either method, the amount of effective generation rejection within the Readjustment period will not exceed 80% of the normal operating spinning reserve of the MAPP system (one half of 1.5 times the largest unit). The following limits apply to generation rejection when tripping generating units:*

- *Hydro – up to one plant*
- *Fossil – Up to two units at a plant*

H. *Transmission Reconfiguration – Automatic and operator initiated tripping of transmission lines or transformers within the readjustment period.*

I. *Non-firm load shed – Automatic or manual tripping of interruptible load being supplied under MAPP service schedule L or the pre-determined re-dispatching of Non-Firm Point-to-Point Transmission service within the readjustment period.*

3. *The following additional readjustments may be considered for all NERC Category C contingencies.*

    A. *Generation rejection – One nuclear unit may be rejected as long as the loss is less than 80% of the normal operating spinning reserve of the MAPP System (one half of 1.5 times the largest unit).*

    B. *Firm load shed – Automatic or manual tripping of firm Network or Native Load or the predetermined re-dispatching of firm Point-to-Point Transmission Service and Firm Transmission Network Service.*

4. *The following additional readjustments may be considered for all NERC Category D contingencies.*

    A. *It is assumed that some planned and controlled islanding will occur for the most credible extreme disturbances. Automatic under-frequency load shedding as specified in Standard III.D is expected to arrest declining frequency and generation rejection is expected to arrest increasing frequency in order to assure continued operation within the resulting islands.*

    B. *Automatic under-voltage load shedding as specified in Standard III.E is permissible to arrest declining voltages and prevent widespread voltage collapse.*

5. *The criteria listed in the MAPP Disturbance-Performance Table are the default limits. Specific buses, control areas or companies may have more or less restrictive criteria. Refer to the current MAPP members' reliability criteria and study procedures manual for a complete listing of specific reliability criteria.*
6. *Additional voltage requirements associated with voltage stability are specified in Standard I.D. If it can be demonstrated that post transient voltage deviations that are less than the values in the MAPP disturbance-performance table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperated in mutually resolving the problem.*
7. *Apparent impedance transient swings into the inner tow zones of distance relay are unacceptable for NERC/MAPP category B and C1, C3, C4 and C5 disturbances, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC/MAPP category C2, C6, C7, C8 and C9 disturbances, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.*
8. *A one-cycle safety margin must be added to the actual or planned fault clearing time.*
9. *The machine rotor angle damping ratio is determined by modal analysis (e.g. Prony analysis or equivalent). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.9 or the damping factor must be greater than 10%. Refer to the current MAPP members reliability criteria and study procedures manual for a description of the calculation methodology.*
10. *The parameters listed the MAPP disturbance-performance table are the default minimum limits on MAPP's Canada-U.S. interface. Refer to the MAPP members reliability criteria and study procedure manual for a complete listing of specific reliability criteria, detailed descriptions and margin definitions.*

Appendix L: SOL (IROL) Methodology for the Planning Horizon Definitions:

R1 SOL Methodology:

The MISO establishes SOLs and IROLs for both the Operating and 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-003 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 Extranet Reliability Authority page and the MISO ftp site.

Instructions for access for the Extranet Reliability Authority are found at: http://extranet.midwestiso.org/How%20To%20Activate%20RA%20Information%20Access.pdf

Instructions for access for the MTEP ftp site are found at: https://www.misoenergy.org/Library/Repository/Study/MTEP/FTP%20Site%20Access%20Request%20Form.pdf

The methodology for developing SOLs and IROLs for the Planning Horizon is described in this document.

R1.1 Applicability of SOLs for the Planning Horizon:

This methodology is applicable for developing SOLs used in the planning horizon.

R1.2 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 transfers consistent with FAC-013-2. The SOL condition shall not produce any facility loading or voltage condition that exceeds the most limiting element that determines the Facility Rating.

R1.3 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 transfers consistent with FAC-013-2, for which instability, uncontrolled separation, or Cascading Outages are projected to occur.

R2 Determination of SOL Conditions in the Planning Horizon:

Near and longer term planning addresses identification of needs and solutions in the time frame of 1 to 10 years, with particular focus on the first 5 years. Screening reliability analyses are performed in the 6-10 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 transfer capability (FCITC) 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-001-0 through TPL-003-0, 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:

R2.1 Pre Contingency State:

The transmission system is modeled under NERC Category A conditions (e.g. system intact) using both steady-state and dynamic stability analysis. Potential planning criteria violations (thermal overloads 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.

R2.2 Post Contingency State:

The transmission system is modeled under NERC Category B and C 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 B using Transfer Capability analyses. Planning criteria violations (thermal overloads 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 limit for NERC Category B contingent conditions and to the extent either dynamic or voltage instability is identified at the FCITC 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.

R2.3 Single Contingency System Response:

For the near-term planning horizon, any potential criteria violations under NERC Category B 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.

R2.4, R2.5, R2.6, R2.6.1 Multiple Contingency System Response:

For the near-term planning horizon, modeled criteria violations under NERC Category C 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.

R3 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 MISO SOL methodology consists of each of the following elements:

R3.1 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 Authority area as well as any critical modeling details from other Planning Authority 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 1 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 Interconnection Agreements;
- 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.

R3.2 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 through TPL003, or any applicable local or Regional Entity planning criteria or guidelines. Below is a list of typical contingency categories tested.

- NERC Category A is system intact or no contingency event.
- All Category B faulted events for systems under MISO operational control. Generally, greater than 100 kV, but includes some 69 kV. Category B includes single generator, transmission circuit and transformer outages. It also includes single pole block of DC lines.
- NERC Category C faulted events. The more severe events will be studied per the standards. All events will be documented and studied over study cycle. Transmission Owners and MISO staff will document NERC Category C coverage.

R3.3 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 Owners as potentially significant for local system reliability studies.

R3.4 Remedial Action Plans:

The MISO base model for evaluating SOLs includes analysis of known Special Protection Systems and Remedial Action Plans.

R3.5 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 4.4 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 7.2). 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.

R3.6 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:

1. **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[4] of load in excess of 1000 MW. Monitoring of MISO facilities shall be performed at the following facility rating thresholds (consistent with PRC-023-2):
   - If the Facility Rating is based on a loading duration of up to and including four hours, the circuit loading threshold is 115% 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 120% of the Facility Rating.
   - If the Facility Rating is based on a loading duration of greater than eight hours, the circuit loading threshold is 130% of the Facility Rating.

   To the extent facility rating thresholds established by MISO Transmission Owners (for purposes of IROL identification) are lower than the above thresholds, MISO will use these rating thresholds.

   Cascading test methodology is documented in more detail under section 4.3.7.1 of this BPM.

2. **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.

[4] Refer to Transmission Planning BPM-020, Section 4.3 for additional information defining cascading loss

3. **<u>Near Term Transfer Capability based studies</u>**: The following studies shall be conducted to determine IROLs based on transfer studies. Transfers to be studied shall be established pursuant to FAC-013-2 Transfer Capability Methodology documented in Appendix N of this TP-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 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 IROL limited facilities.

a) Thermal Study:

Steady State testing using multiple contingencies performed while monitoring MISO facilities at the following facility rating thresholds (consistent with PRC-023-2):

- If the Facility Rating is based on a loading duration of up to and including four hours, the circuit loading threshold is 115% 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 120% of the Facility Rating.
- If the Facility Rating is based on a loading duration of greater than eight hours, the circuit loading threshold is 130% of the Facility Rating.

To the extent facility rating thresholds established by MISO Transmission Owners (for purposes of IROL identification) are lower than the above thresholds, MISO will use these 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.

b) 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.

c) 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 Owners, 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.

R4 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.

R4.1 Adjacent Planning Authority:

Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the SOL Methodology.

R4.2 Reliability Coordinator and Transmission Operator:

Each Reliability Coordinator (MISO) and Transmission Operator that operates any portion of the MISO's Planning Authority Area.

R4.3 Transmission Planner:

Each Transmission Planner that plans a portion of the MISO Planning Authority Area

R5 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 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.

R6 Data Retention Period:

The MISO shall keep all superseded portions of this SOL Methodology for 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 years.

Appendix M: MISO Planning Horizon PRC-023-2 Applicable Facility Identification Procedure

R6. Pursuant to requirement R6, MISO shall conduct an annual assessment as part of the MISO Transmission Expansion Plan (MTEP) study to identify transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV for which Transmission Owners, Generation Owners and Distribution Provides must adhere to PRC-023-2, Requirements 1 through 5 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. MISO shall identify these circuits once a year pursuant to the criteria documented below that is consistent with each sub requirement within Attachment B of PRC-023-2. To the extent, inputs that fall under Attachment B sub requirements are developed more frequently than once a year, MISO shall still update the list once a year upon completion of its annual reliability assessment.

This PRC-023 Applicable Facilities list is developed to identify only those facilities for which the Required Entities must adhere to Requirements 1 through 5 of the standard.

1. **Criterion B1**: Upon completion of MISO's reliability assessment, MISO shall 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 criteria based on additions or deletions to the permanent flowgate list annually.
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 TP-BPM.
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. To the extent, NPIR revisions occur within a given year, consistent with the requirement, MISO will still update the list once a year upon completion of its annual reliability assessment.

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. The contingencies selected will be determined from MISO reliability assessment, where over 100 MW of firm load curtailment is identified to meet system performance requirements for NERC C3 contingencies. In order to monitor thermal loading, MISO shall utilize facility rating thresholds consistent with sub requirements – B4a, B4b, B4c and B4d:
    a. Simulate double contingency combinations without manual system adjustments in between the two contingencies.
    b. Facility Rating assigned to that circuit in consultation with the Facility Owner and included in MISO Transmission Expansion Plan base models
    c. Where more than one applicable rating exists, the rating based on the loading duration nearest four hours
    d. Rating based on loading duration assumed:
        1. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit loading threshold is 115% of the Facility Rating
        2. 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 120% of the Facility Rating.
        3. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit loading threshold is 130% of the Facility Rating.
        4. To the extent facility rating thresholds established by MISO Transmission Owners (for purposes of IROL identification) are lower than the outlined thresholds, MISO will use the lower rating thresholds.
    e. MISO will exclude radially operated circuits

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. MISO establishes its IROLs as part of its annual reliability analyses. In addition to the monitored facility that is part of facility list pursuant to sub requirement B2, MISO shall also include the associated contingent element facilities within its facility list.

6. **Criterion B6**: The MISO shall supplement the list of facilities developed pursuant to sub requirements B1 through B5 above with additional facilities identified by the MISO Transmission Owners. MISO will solicit its Transmission Owners for this list once a year before establishing its annual facility list.

R6.1 MISO shall annually develop and maintain a list of circuits that meet any of the criteria detailed in Requirement 6 that would be subject to Requirements 1 through 5 listed in PRC-023-2. This list shall be created annually and will include identification of the first calendar year for which the circuit meets any of the criteria described in Requirement 6. The list will be available on the MISO extranet site. {Add extranet link here}

R6.2 MISO shall make the list of facilities available to the appropriate Regional entities, including Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers. If any change is made to the list of facilities, a new list shall be posted within 30 days of any such change.

Expansion Planning shall also send a notification to all appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers whenever a new list is posted. The list of facilities shall be posted in both Excel and PDF format.

Transmission Owners of 100-200 kV class circuits[i] to which the relay loadability standard (PRC-023-2) shall apply, as referenced by MISO Transmission Asset Management - Expansion Planning will also be identified in the published list.

Appendix N: MISO Transfer Capability Methodology in compliance with FAC-013-2

Pursuant to NERC Reliability Standard FAC-013-2, MISO documents its Transfer Capability Methodology applicable to the Near-Term Transmission Planning Horizon within Appendix N of its Transmission Planning Business Practice Manual (TP-BPM-020). 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 above these base transfer levels.

R1 Transfer Capability Methodology:

This Appendix N constitutes MISO's documented methodology, which it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). This methodology includes the following information:

R1.1 Transfer Selection Criteria:

Prior to commencement of its annual MTEP Transmission Planning studies, 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. A First Contingency Incremental Transfer Capability (FCITC) for each studied transfer path shall be established based on the most limiting of the Steady State, Voltage Stability and Transient Stability analyses. These transfers will be selected based on the following criteria:

1. **Demand Forecast**: Transfers simulating increases in demand shall be conducted on MTEP 5 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 upto 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.
2. **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 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.
3. **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 5% lower than historic flows on the same interface

4. **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 support of the standard, there will typically be approximately three to five models built annually for performing transfer analysis, unless stakeholders agree otherwise. Planning horizon transfer simulation models created shall be developed using, but not limited to, the criteria outlined in R1.1.

R1.2 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 the Transmission Planning Business Practices Manual (TP-BPM).

R1.3 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 TP-BPM.

R1.4 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:

R1.4.1 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. Generators projected to be retired in the five year planning horizon are not dispatched. Additional details on MTEP model generation dispatch is documented under section 3.3.3 of this TP-BPM.

R1.4.2 Transmission System Topology:

Projected transmission system topology in the 5 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 in Compliance with FAC-010-2, Section R3.1 for additional details on system topology.

R1.4.3 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 ERAG 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 TP-BPM.

R1.4.4 Current 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

R1.4.5 Parallel Path (loop flow) Adjustments:

Because it is recognized that transfers occur on all transmission paths that are part of the ac interconnected system, in establishing transfer capability, MISO will monitor and recognize neighboring or adjacent interconnected system limits.

R1.4.6 Contingencies:

All single contingencies will be applied in testing transfer capability. In addition select double contingency outages will also be simulated in establishing transfer capability for off-peak conditions. Consideration of this select list of double contingencies ensures that the more significant maintenance outages (not otherwise reflected in Near-Term planning cases) are accounted for in establishing transfer capability. These multiple contingencies will only be simulated in transfers studied in off-peak cases where maintenance outages are most likely. These double contingencies will be selected based on MTEP planning studies where firm curtailment is identified to be needed to meet system performance requirements for Category C3 contingencies.

Please refer to Appendix L: MISO SOL – IROL Methodology in Compliance with FAC-010-2, Section R3.2 for additional details on contingencies simulated.

R1.4.7 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 __ of the TP-BPM shall be included in monitored facility list.

R1.5 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 upto 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.

R2 Issuance of Methodology by PC:

A notice of issuance of Transfer Capability Methodology shall be sent out in accordance with Sections R2.1 and R2.2 below.

R2.1 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.

R2.2 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 30 calendar days of receiving that written request.

R3 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 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 studies shall be performed annually. The determination of list of transfers will be completed by the end of first quarter of each year. 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.

R4 Annual assessment of Transfer Capability:

As noted above, MISO shall conduct an assessment of Transfer Capability on an annual basis. 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 year out planning year.

R5 Availability of Study Results:

MISO shall make the documented Transfer Capability assessment results available within 45 calendar days of completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2.

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 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.

R6 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 45 calendar days of receipt of request, subject to MISO legal and regulatory obligations regarding the disclosure of confidential and/or sensitive information.

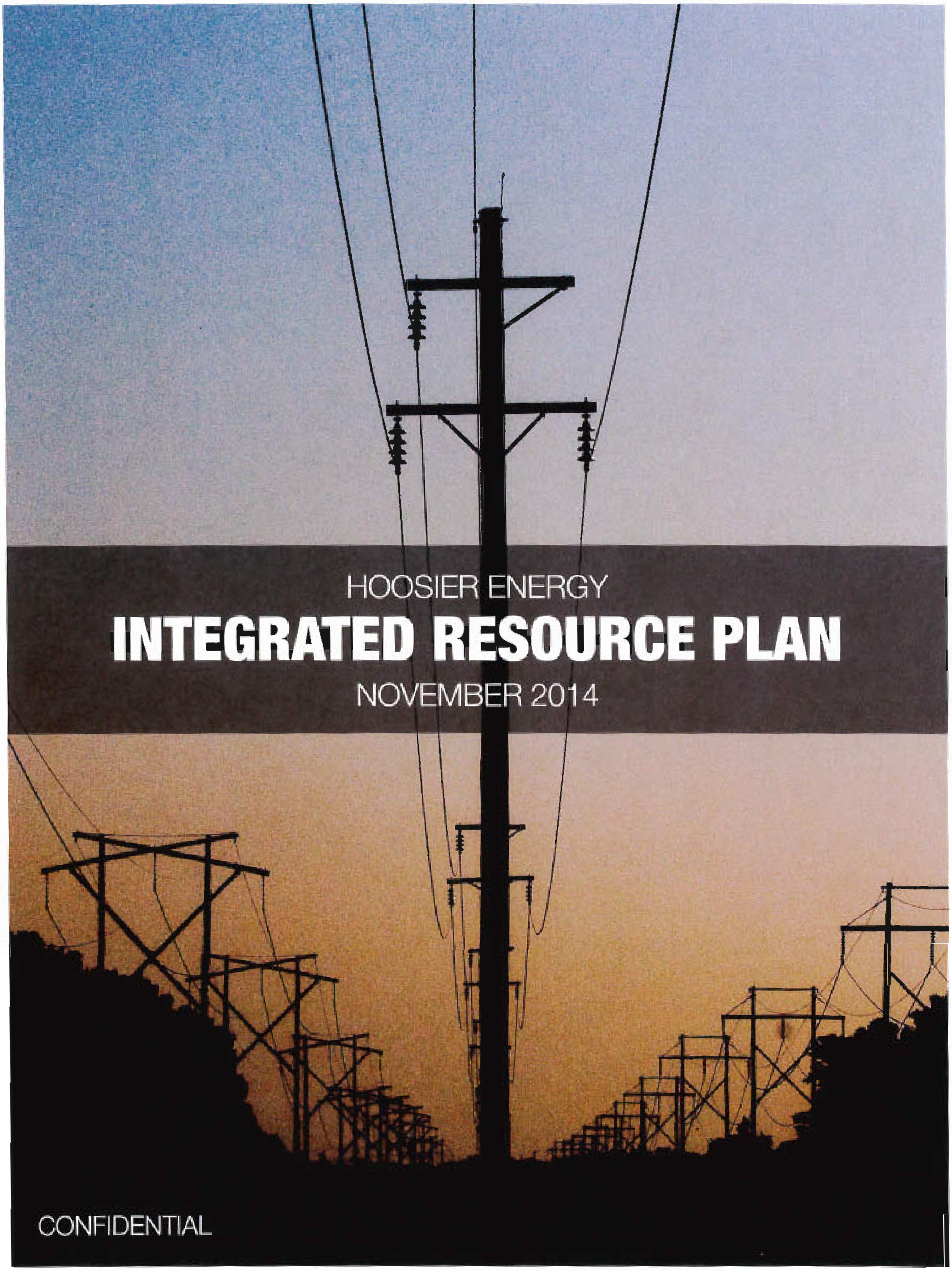
Appendix H
FERC Form 715 – Part 6

Evaluation of System Performance

Redacted

Appendix I

Executive Summary



HOOSIER ENERGY

INTEGRATED RESOURCE PLAN

NOVEMBER 2014

CONFIDENTIAL

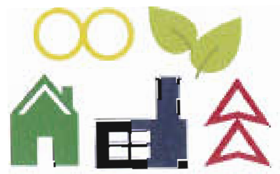
WHAT IS RESOURCE PLANNING?

Key features

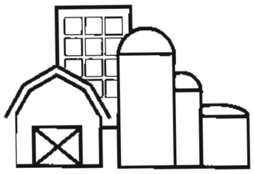
Inputs

- Member input
- Board policies
- Regulatory requirements
- Risk adjusted least cost

Resource mix



Energy need



Costs and rates

Planning Process

Requirements considered + Timeline established + Resources evaluated

= Long range resource plan

The resource planning process projects future consumer needs and comprehensively evaluates options for meeting those needs.

Resource plan inputs include:

- Future consumer needs
- Resource strategies, regulatory policies and member input
- Financial aspects of plan implementation including financing costs and rate structures

Risk analysis

Inputs for the resource planning process are not absolute. Many variables are analyzed to understand the implications and interaction of inputs and impacts on costs and rates.

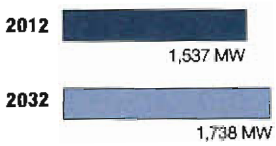
Uncertain future

Resource plans will change over time. Course adjustments will reflect input from members and regulators, changes in growth patterns and financial considerations.

THE HOOSIER ENERGY POWER NETWORK

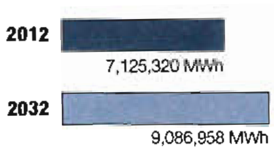
Peak demand

Member peak demand is projected to increase 13 percent by 2032.



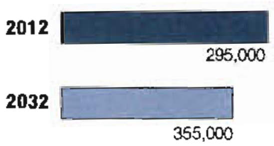
Energy requirements

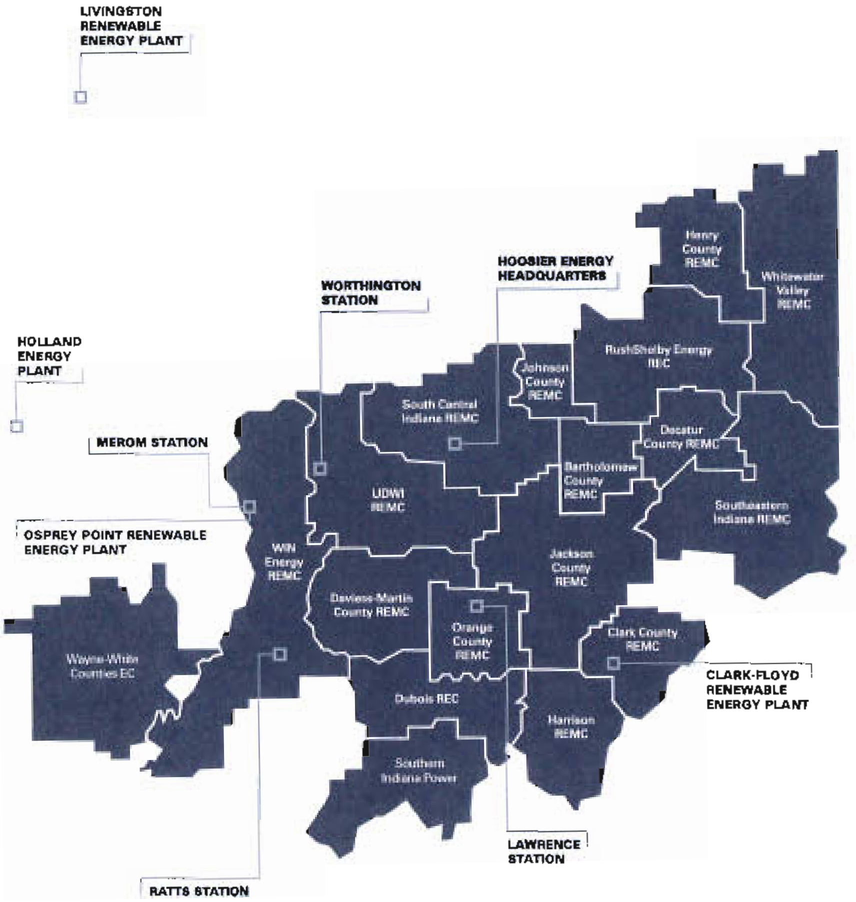
Member energy needs are projected to increase 24 percent by 2032.



Number of consumers

The number of consumers is expected to increase 20 percent by 2032.





ELECTRIC CONSUMER FACTS

47%

Consumers who own a smartphone.

50%

Efficiency increase for refrigerators since 2000.

75%

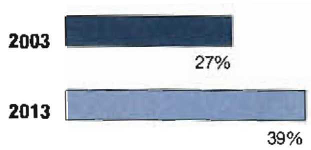
Residential consumers with electric water heaters.

1,273 kWh

Since 1990, average household monthly electricity use remained relatively constant.

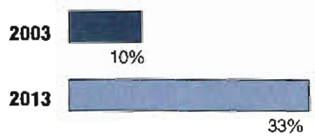
Growing market share for electric heat

The percentage of consumers using electric heat increased by one-third over the past ten years.



Efficient heat pumps drive electric heating

Heat pumps are now used by one-third of all households that rely on electric heat.



MEETING MEMBER NEEDS

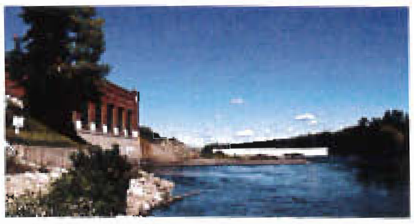

Merom Station


Ratts Station


Holland Energy


Lawrence Station

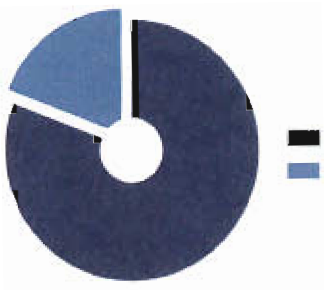

Worthington Station


Renewable facilities

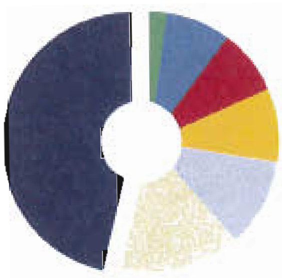
Resource portfolio changes: 2000 to 2014

The Hoosier Energy portfolio has grown and diversified to meet member needs and manage risk.

2000 capacity – 1,250 MW



2014 capacity – 2,100 MW



Hoosier Energy's resource portfolio continues to evolve to meet member needs in a changing market.

Increased capacity

- The portfolio increased by more than 65 percent between 2000 and 2014.

Diversity

- Focus on adding renewable resources
- Purchased power – Purchased Power contracts are "slice-of-system" agreements.
- Fuels – All Hoosier Energy-owned assets added since 2000 use natural gas or renewable resources.

Market changes

- The MISO electricity market began functioning in 2005. Hoosier Energy was a founding member of MISO and the market provides price transparency, reserve sharing, and mitigation of concentration risks.
- The MISO market supports efficient power supply. The market also provides short-term sales opportunities and a power supply alternative to supplement Hoosier Energy's resources.

RESOURCE MIX 2014

Baseload

The coal-fired Merom Station has a production capacity of nearly 1,000 megawatts and complies with all emission requirements. Other resources include the 250 MW Ratts Station and 200 MW of Purchased Power Agreements.

Intermediate

Holland Energy, the Hoosier Energy/ Wabash Valley 630-megawatt natural gas combined cycle plant, is an important component of the portfolio that typically provides needed energy during peak months.

Peaking

Lawrence and Worthington generating stations efficiently provide electricity from natural gas turbines to meet short term needs. Fast start capability adds power supply flexibility and the units help meet MISO reserve requirements.

Energy Efficiency

Since 2009, cumulative savings from demand-side management programs total more than 130,000 megawatt-hours. Summer demand has been reduced by a cumulative total of 30 megawatts and winter demand by 51 megawatts.

Renewables

Hoosier Energy has developed high-capacity factor landfill gas and coal bed methane projects as well as PPAs that add wind and hydro resources to meet the voluntary Board program of 10 percent of member energy requirements by 2025 from renewables..

RESOURCE ROLES

Baseload

Baseload resources refers to units with higher capacity factors that are available to operate throughout the year. Other resources could provide baseload energy but far less economically.

Intermediate

Intermediate resources provide energy for extended periods of the day. These resources are used to meet increasing demand in weekday hours. A combined cycle natural gas power plant is this type of resource.

Peaking

Peaking resources provide energy on very short notice to meet customer energy needs during very few hours of the year. Natural gas combustion turbines are ideal for this application and demand response can help meet this need.

Energy efficiency

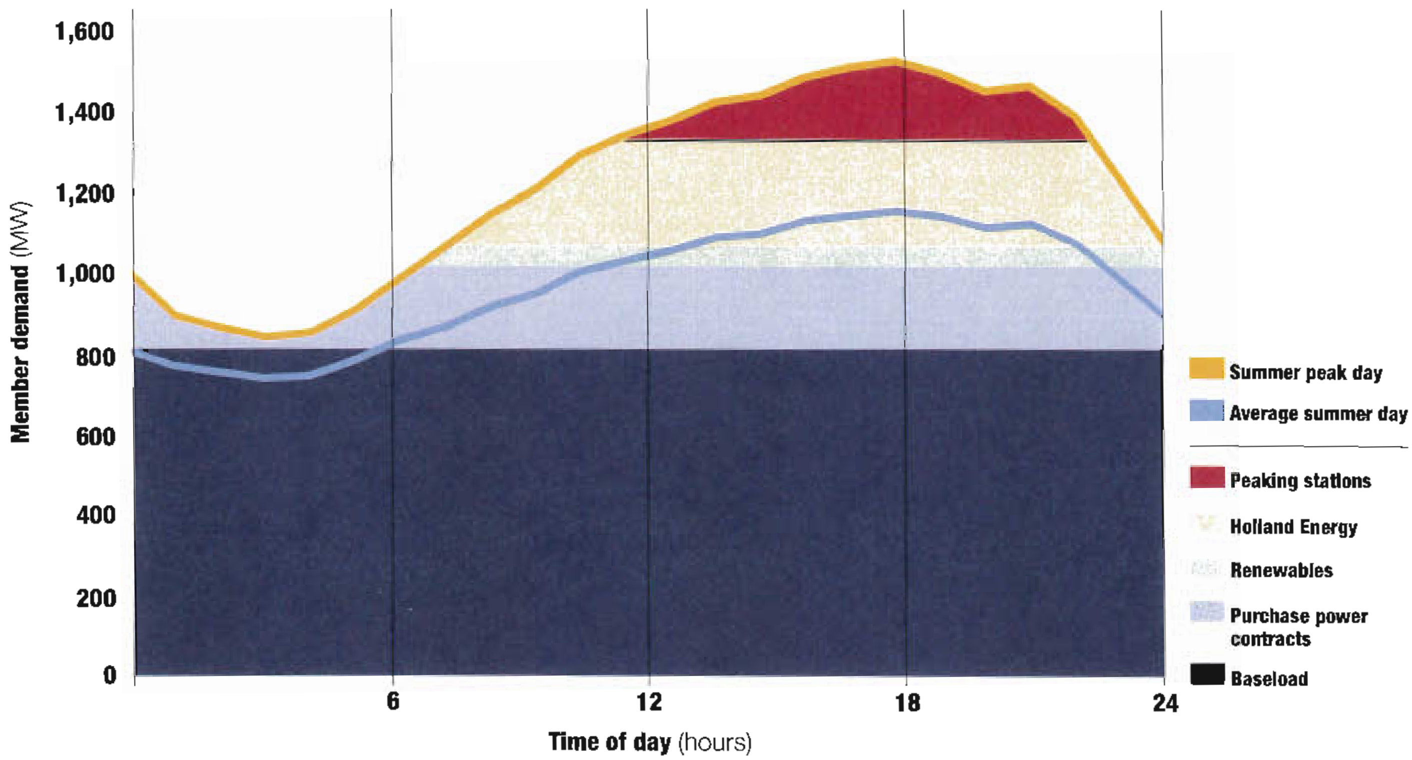
Consumers can help manage system demand through energy efficiency. When consumers use new strategies, products and technologies to reduce consumption, the effect is equivalent to adding generation.

Renewables

Renewable generation includes wind, hydro, solar and biomass facilities that do not rely on traditional fossil fuels. Most renewable facilities operate intermittently and require backup capacity from other generation to meet load and MISO requirements.

RESOURCE CONTRIBUTIONS

How assets will meet member needs in 2014



FUELS

Coal

The proposed rule issued by the EPA on June 2, 2014 requires Indiana electric utilities to reduce carbon emission rates 20 percent, from 2012 levels, by 2030. This mandate, along with future environmental rules, the resulting potential for significant cost increases, and low natural gas prices make new coal fired generation an uneconomic resource choice.

Natural gas

Natural gas combined cycle plants offer low capital costs and flexible operating characteristics. Low fuel costs and moderate environmental risk make natural gas attractive although price volatility and pipeline capacity emerged as issues last winter.

Energy efficiency

Energy efficiency offers options to help manage future power requirements. Results depend upon customer participation and the ability to implement cost-effective programs.

Renewable energy

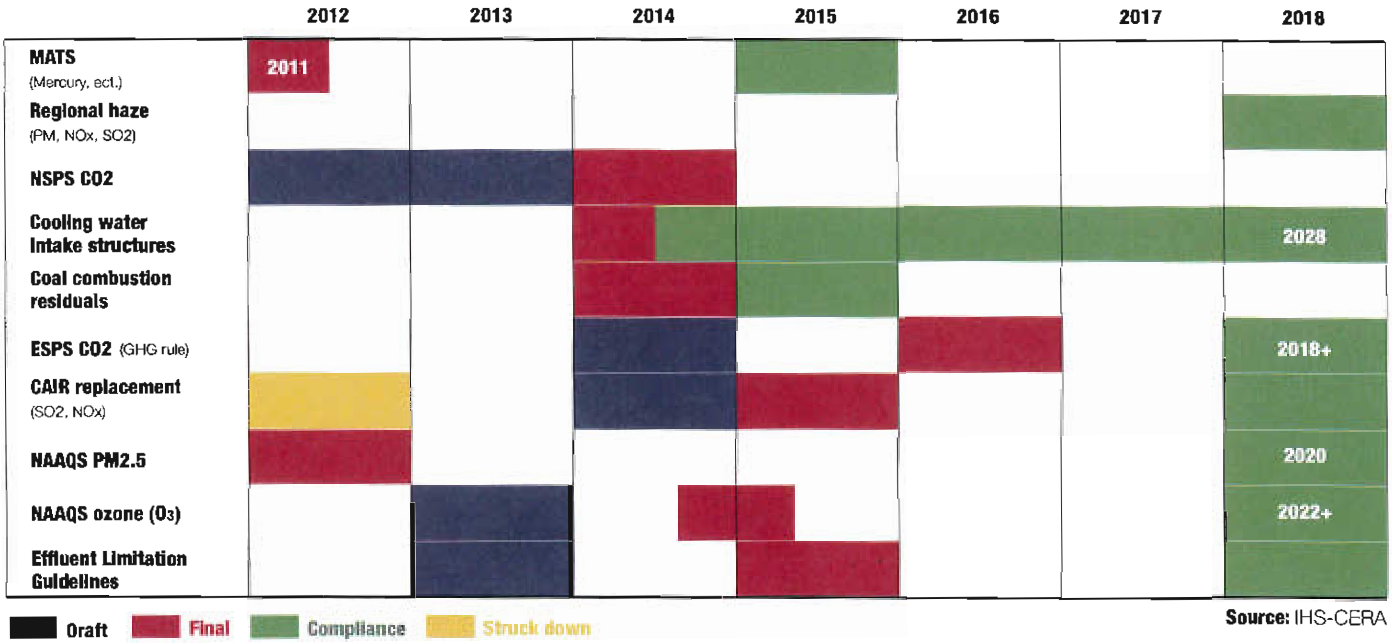
Renewable energy is the fastest-growing source of new generation. Very large tax incentives, public policy requirements and consumer support have led to widespread construction of wind and solar projects across the nation. Continued expansion will likely require additional transmission investment beyond current transmission plans, which include MISO's $5.6 billion MVP portfolio.

KEY RISKS

Environmental rules and regulations

Coal generation continues to be a target for new rules and tightening regulations. A broad strategy to reduce dependency on coal and increase reliance on natural gas and renewables is warranted. The chart below reflects an outlook for current rules developed by IHS-CERA.

Federal environmental rules



Source: IHS-CERA

As shown in the timeline above, the Mercury and Air Toxins (or MATS) rule is effective in 2015 or 2016 for coal generators that are granted a one year waiver by the state. The MATS rule will require the retirement of coal plants and creates the potential for supply disruptions under extreme conditions, such as a repeat of this past winter's Polar Vortex.

KEY RISKS

Clean Air Act 111(d) Existing Plant Rulemaking

EPA released the proposed greenhouse gas rules for existing plants in June 2014 and this new regulation represents the primary risk to consistent operation of coal-fired facilities. The rule establishes different target emission rates (pounds of CO2 per MWh) for each state due to regional variations in generation mix and electricity consumption. An overall 20 percent reduction from 2012 levels by 2030 is EPAs target for Indiana.

The rule requires states to develop and submit implementation plans and uses four "building blocks" to determine expected CO2 reductions. EPA targets for Indiana include:

1. Improve efficiency of all coal plants by 6%.

2. Increase dispatch of existing natural gas combined-cycle units with a goal of 70 percent capacity factor.

3. Increase generation from renewable resources.

4. Increase energy efficiency to an 11 percent cumulative savings level by 2029.

EPA plans to issue a final rule by June 2015. The target date for states to submit their proposed plans to EPA is June 2016, but states can apply for a one-year extension. After a plan is submitted, EPA will have a year to either approve plans or send them back to states for revision. If a state does not submit an adequate plan, EPA is authorized to impose a federal plan to drive the necessary reductions.

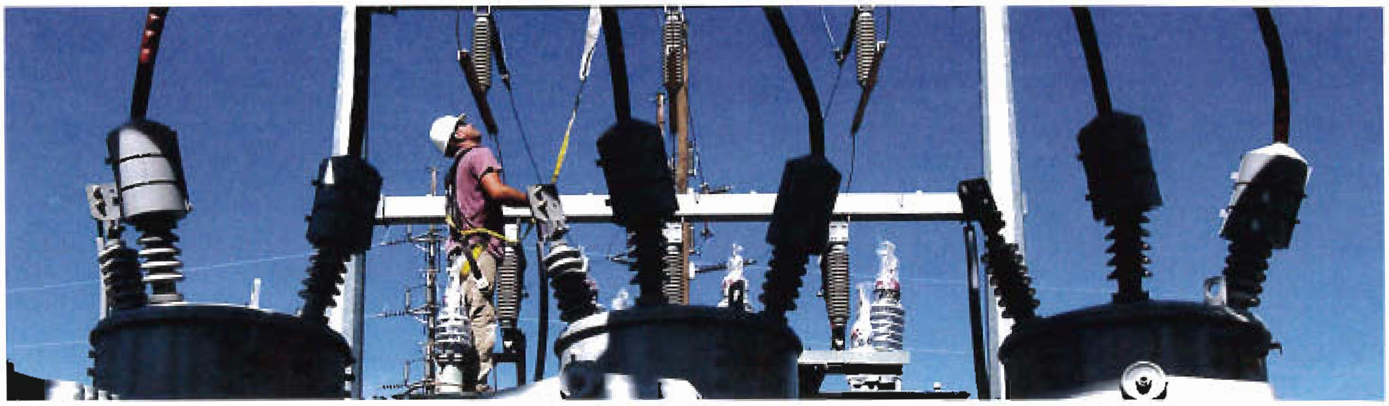
Along with NRECA, the state and many others, Hoosier Energy is now analyzing the 1,600 page rule.

Midcontinent Independent System Operator

MISO modified its capacity market in June 2013. The market now divides the MISO footprint into zones based upon transmission capabilities. The intent is to identify and value congestion related to capacity and to reflect transmission limits among zones during peak conditions. Hoosier's load and resources are contained within Zone 4 (Illinois) and Zone 6 (Indiana).

For each planning year, MISO develops a resource adequacy requirement and holds an auction to determine a capacity clearing price for each zone. The auction for the June 1, 2014 planning year cleared at $16.75/MW-day for both Zones 4 and 6, which is a 1600 percent increase above the 2013 auction results. These results indicate that there remains a concern about the availability of capacity in MISO's North and Central regions, which are currently forecasted to be 2 GW short of MISO's resource requirements including reserves for the June 1, 2016 Planning Year.

KEY RISKS



Transmission price constraints

Congestion is a significant cost risk. Congestion is a result of the locational marginal pricing (LMP) methodology, which reflects the value of energy at specified locations throughout the MISO footprint. If the same priced electricity can reach all locations throughout the grid, then LMPs are the same. When there is transmission congestion generally caused by heavy use of the transmission system, energy cannot flow either from or to other locations. This forces more expensive and/or more advantageously located electricity to flow in order to meet the demand. As a result, the LMP is higher in the constrained locations.

Hoosier Energy has contracted with Quanta Technology to analyze congestion between our generation stations and several MISO pricing points, including Hoosier Energy's load zones. The purpose of this analysis will be to model and assess the current and future congestion impacts. The analysis will include the MISO-approved transmission expansion plans and determine the impact of the proposed transmission projects. In addition, the analysis will assess potential mitigation measures that might be available to alter the expected congestion impacts on Hoosier Energy's generation stations.

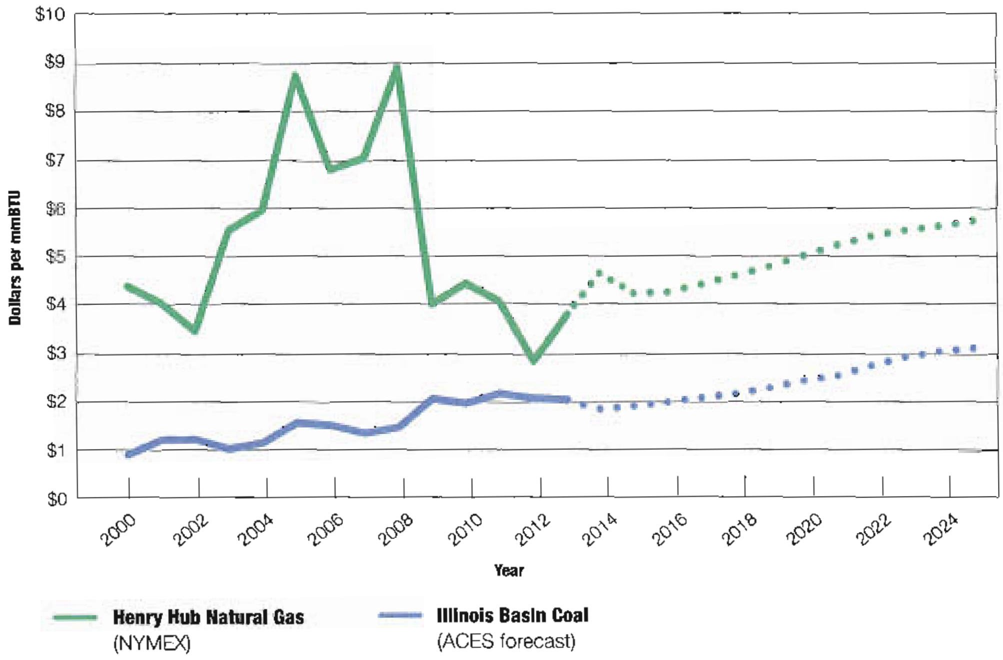
Hoosier Energy also faces risks associated with the development of independent transmission companies and new transmission projects authorized by MISO. The independent transmission companies (or transcos) have several advantages over vertically integrated utilities including more autonomy through formula rates and the potential for higher returns. With respect to new transmission projects, a broad group of parties, including Hoosier Energy, challenged MISO's methodology for recovery of transmission costs all the way to the United States Supreme Court. In February of 2014, the Supreme Court elected not to hear the appeal essentially confirming MISO's plan to spread the cost of certain projects across the MISO footprint.

Another risk is the threat to Hoosier Energy's grandfathered agreements or GFAs that provide about $4 million in annual benefits to members, including a hedge against congestion costs. Hoosier Energy has successfully fought prior attempts to eliminate GFAs but the potential for future threats remain.

KEY RISKS

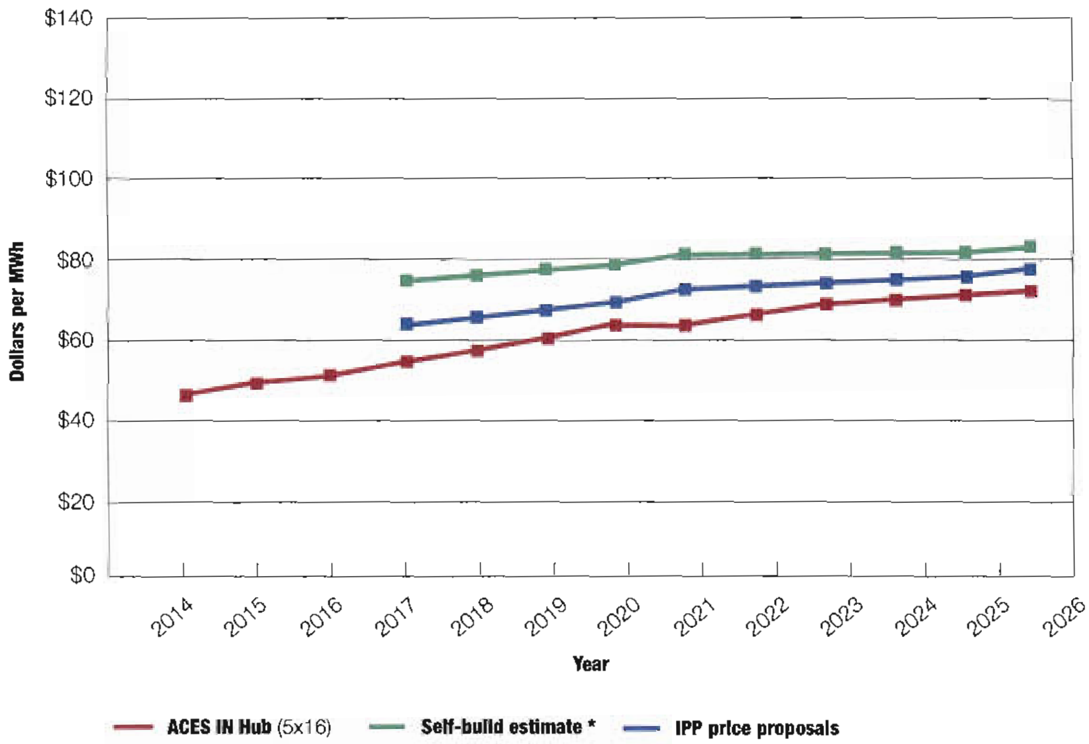
Fuel cost

This chart shows the volatility of natural gas and coal prices. A long term strategy to continue to diversify Hoosier Energy's fuel mix will be prudent. While the long-term natural gas price forecast shows a stable, upward trend, the historical portion of the graph shows the reality of volatile natural gas prices.



Markets

The forward power market remains a viable alternative to satisfy a portion of member needs but the lead time and difficulty to add new resources creates exposure and risk to market price swings. Long-term market exposure can be hedged through assets or purchased power agreements. The highlighted area on the chart shows the potential energy cost range for a new combined-cycle plant.

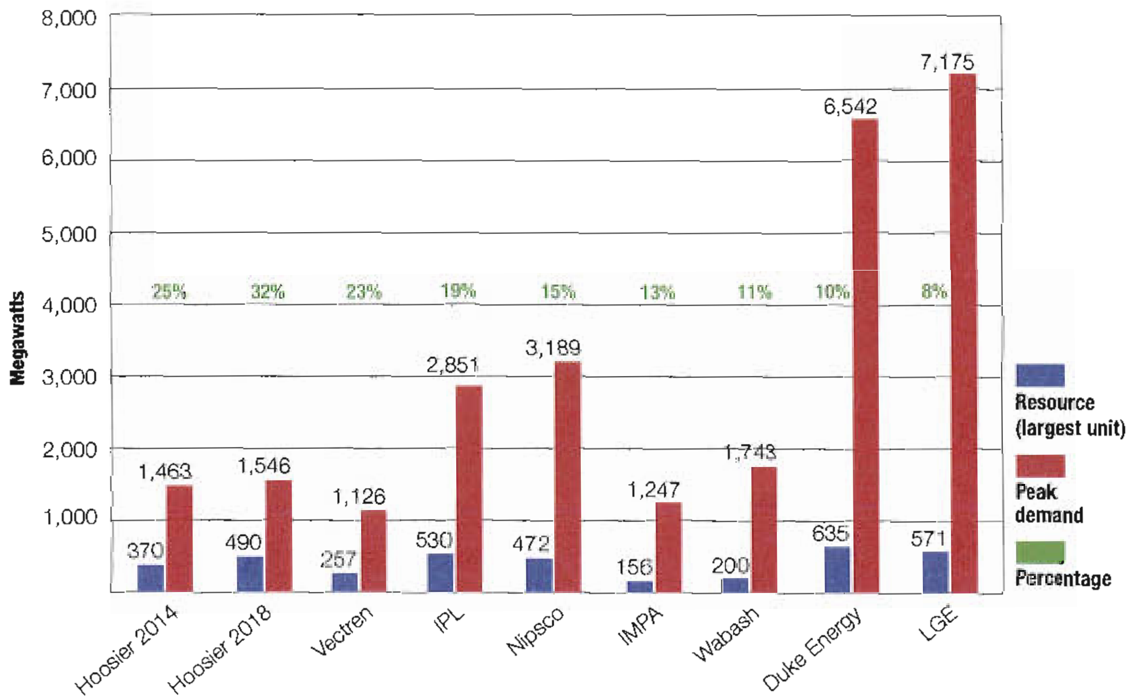


* Based on a new 600 MW combined-cycle gas plant @ $1,000/KW capital costs and assuming NYMEX gas prices of $4.80/mmBTU in 2017 increasing to $6.00/mmBTU in 2026.

KEY RISKS

Concentration/shaft risk

Hoosier Energy continues to face significant unit concentration or "shaft risk" as a result of relying on Merom Station to meet a high proportion of member energy needs. This risk suggests the G&T should continue a strategy of making long-term, Unit Contingent (UC) sales from Merom. Future UC sales may accelerate the need for additional resources but the strategy provides both resource and fuel diversity. A strategic target of limiting shaft risk to no more than 25 percent of Hoosier Energy's member load may be a prudent long term objective.



Counterparties

Hoosier Energy members are well served by maintaining a mix of owned and purchased resources. In addition to system purchased power agreements, Hoosier Energy uses PPAs to acquire wind and hydro renewable resources. Hoosier Energy owned generation resources includes a mix of sole and jointly-owned facilities. The only fossil fuel facility that Hoosier Energy does not either share ownership in or sell unit contingent power from is Worthington, the smallest plant in the Hoosier Energy fleet. Hoosier Energy sells unit contingent power to Wabash Valley from Merom through the end of 2017 and from Ratts station until that plant is idled. The G&Ts worked jointly to develop the Lawrence peaking facility in 2005 and purchase the Holland combined-cycle facility in 2009.

Future generation resource options will likely include additional partnerships with existing or new counterparties. Options may include shared ownership or Hoosier Energy taking a partial interest in generation resources owned by other companies.

RESOURCE CHANGES

2015-2017

Capacity needs in 2015-2017 are based upon the following:

- 276 MW unit contingent sale from the Merom Station.
- Ratts Station plant idled.
- Additional renewable resources including:
  - 25 MW Rail Splitter Wind PPA
  - 10 MW Solar PPA
  - 16 MW Orchard Hills LFG
  - 4 MW Cabin Creek LFG
- 50 MW purchased power contract begins on January 1, 2016.
- December 31, 2017 expiration of purchased power contract for 100 MW.

2018-2023

- The capacity expansion plan assumes a 200 MW sale from Merom and shows a deficit of 120 to 175 MW during this period.
- New renewable resource additions are expected in order to comply with the voluntary Board program of 10 percent of member energy requirements by 2025 from renewables.
- December 31, 2023 expiration of purchased power contract for 100 MW.

2024 and beyond

- Proposed 200 MW UC sale is expected to continue.
- December 31, 2025 expiration of purchased power contract for 50 MW. Decisions on extending the agreements are a prerequisite to determining the need for additional resources during the period.

ACTION PLAN

UNIT CONTINGENT SALES	Pursue 200 MW sale from Merom beginning in 2018 to manage shaft risk. Other options include system sales.
MARKET PURCHASES	Use market purchases to meet 100-125 MW short term needs during 2015-2017 period, hedging strategies to reduce market price risk, and monitor markets for opportunities.
DSM, RENEWABLE RESOURCES	Develop DSM resources with members; pursue additional renewable opportunities consistent with the Board Policy renewable portfolio standard of 10 percent of member energy requirements by 2025.
EVALUATE RESOURCE OPTIONS	Evaluate options to replace 100 MW purchased power contract (expires December 31, 2017) including contract extension, long-term PPA with other parties, buying or building capacity. Evaluate short term opportunities to buy peaking capacity in MISO as hedge against market price increases and a future need for high cost CT units. Develop potential partnerships to mitigate costs and risks.
DEFINE LONG TERM NEEDS	Ventyx Strategist modeling performed by GDS suggests a need for a new generation resource after 2020. Reliance on the market is an option, extension of purchased power contracts is another alternative, and modeling results suggest a new natural gas combined-cycle (CC) facility might offer our least-cost physical resource. All alternatives require further evaluation. Several developers are looking to build new CCs in Indiana. A decision to pursue construction of new combined cycle natural gas generation requires 48 month lead time to permit and build a plant.
IMPLEMENTATION	Implement selected options to meet projected needs including replacement of purchased power contracts that expire at end of 2023 (100 MW) and end of 2025 (50 MW).

ACRONYMS USED

CAIR
Clean Air Interstate Rule

DSM
Demand Side Management

ESPS
Existing Source Performance Standards

FERC
Federal Energy Regulatory Commission

GFA
Grandfathered Agreements

G&T
Generation and Transmission

LRRP
Long Range Resource Plan

MATS
Mercury and Air Toxics Standards

MISO
Midcontinent Independent System Operator

NAAQS
National Ambient Air Quality Standards

NOX
Mono-Nitrogen Oxide

NSPS
New Source Performance Standards

PM2.5
Particulate Matter (<2.5 microns)

PPA
Purchased Power Agreement

PRS
Power Requirement Study

S02
Sulfur Dioxide

UC
Unit Contingent

Appendix J

Cross-Reference to Proposed Rule

Appendix I - Cross-Reference to Proposed Rule

170 IAC 4-7 Section	Requirement	Location
0.1	Applicability	N/A
1	Definitions	N/A
2	Effects of filing integrated resource planning	N/A
2.1	Public Advisory Process	N/A
2.2	Contemporary Issues Technical Conference	N/A
3	Waiver or Variance Request	N/A
4	**Methodology and Documentation**	
(a)	IRP Summary Document	Appendix H
(b)(1)	Inputs, methods, definitions	Section 2 - Section 6
(b)(2)	Forecast datasets	Section 2
(b)(3)	Consumption patterns	Section 2.5
(b)(4)	Customer surveys	Section 2.5.4
(b)(5)	Customer self generation	Section 2.2.7; Section 4.1.6
(b)(6)	Alternative forecast scenarios	Section 2.2.3
(b)(7)	Fuel and inventory procurement	Section 3.2.2
(b)(8)	SO2 Emission allowances	Section 3.2.1
(b)(9)	Expansion planning criteria	Section **4**
(b)(10)(A)	Power flow study	Section 3.2.3
(b)(10)(B)	Dynamic stability study	Section 3.2.3
(b)(10)(C)	Transmission reliability criteria	Section 3.2.3
(b)(11)	Contemporary methods	Section 2
(b)(12)	Avoided cost calculation	Section 3.2.2
(b)(13)	System actual demand	Submitted Electronically
(b)(14)	Public advisory process	N/A
5	**Energy and demand forecasts**	
(a)(1)	Analysis of load shapes	Appendix G
(a)(2)	Disaggregated load shapes	Section 2.5.3
(a)(3)	Disaggregated data & forecasts	Appendix B - Appendix F
(a)(4)	Energy and demand levels	Appendix B - Appendix F
(a)(5)	Weather normalization levels	Section 2.2.6
(a)(6)	Energy and demand forecasts	Appendix B - Appendix F
(a)(7)	Forecast performance	Appendix B - Appendix F
(a)(8)	End-use forecast methodology	Section 2.2
(a)(9)	Load shape data directions	Section 2.2.3
(b)	Alternative peak/energy forecasts	Appendix B - Appendix F
6	**Resource assessment**	
(a)(1)	Net dependable capacity	Section 6.2
(a)(2)	Expected capacity changes	Section 6.2
(a)(3)	Fuel price forecast	Section 6.3.2
(a)(4)	Significant environmental effects	Section 6.3
(a)(5)	Transmission system analysis	FERC Form 715
(a)(6)	Demand-side programs	Appendix A1 & A2
(b)(1)	DSM program description	Appendix A1 & A2
(b)(2)	DSM avoided cost projections	Appendix A1
(b)(3)	DSM customer class affected	Appendix A1

(b)(4)	DSM impact projections	Appendix A1
(b)(5)	DSM program cost projections	Appendix A1
(b)(6)	DSM energy/demand savings	Appendix A1
(b)(7)	DSM program penetration	Appendix A1
(b)(8)	DSM impact on systems	Appendix A1
(c)(1)	Supply-side resource description	Section 6.3
(c)(2)	Utility coordinated cost reduction	Section 5.1
(d)(1)	Transmission expansion	Section 3.2.3; FERC Form 715
(d)(2)	Transmission expansion costs	Section 3.2.3; FERC Form 715
(d)(3)	Power transfer	FERC Form 715
(d)(4)	RTO planning and implementation	Section 3.2.3; FERC Form 715
7	**Selection of future resources**	
(a)	Resource alternative screening	Section 6.3
(a)(1)	Environmental effects	Section 6.3
(a)(2)	Environmental regulation	Section 3.2.1
(b)	DSM tests	Appendix A1 & A2
(c)(	Life cycle NPV impacts	Appendix A1 & A2
(d)(1)	Cost/benefit components	Appendix A1 & A2
(d)(2)	Cost/benefit equation	Appendix A1 & A2
e	DSM test exception	Appendix A1 & A2
(f)	Load build directions	Appendix A1 & A2
8	**Resource integration**	
(a)	Candidate resource portfolios process	Section 5
(b)(1)	Resource plan description	Section 6.5
(b)(2)	Significant factors	Section 5.1.5
(b)(4)	Utilization of all resources	Section 5 - 6
(b)(5)	DSM utilization	Appendix A1 & A2
(b)(6)	Plan operating and capital costs	Section 6.3
(b)(6)	Average cost per kWh	Section 6.3.4
(b)(6)	Annual avoided cost	Section 3.2.2
(b)(6)(D)	Plan resource financing	Section 5.3.2
(b)(7)(A&B)	Regulation assumptions	Section 5 - 6
(b)(7)(B)(i)	Risk management	Section 5.1.3
(b)(7)(D)	PVRR of resource plan	Section 6
(b)(7)(D)	Supply-side selection economics	Section 6
(b)(8)(A)	Demand sensitivity	Section 5 - 6
(b)(8)(B)	Resource cost sensitivity	Section 5 - 6
(b)(8)(C)	Regulatory compliance	Section 5 - 6
(b)(8)(D)	Other factor sensitivities	Section 5 - 6
9	**Short term action plan**	
(1)(A)	Description/objective	Section 1.4
(1)(B)	Progress measurement criteria	Section 1.4
(2)	Implementation schedule	Section 1.4
(3)	Plan budget	Section 6
(4)	Prior STIP vs actual	Section 1.S