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	January	West, Central, East (locations to be announced)

Owners		
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	Carmel or St. Paul (location to be announced)

Allocations 3. Other regular agenda items as developed by MISO planning staff or participants	for dates)	
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.

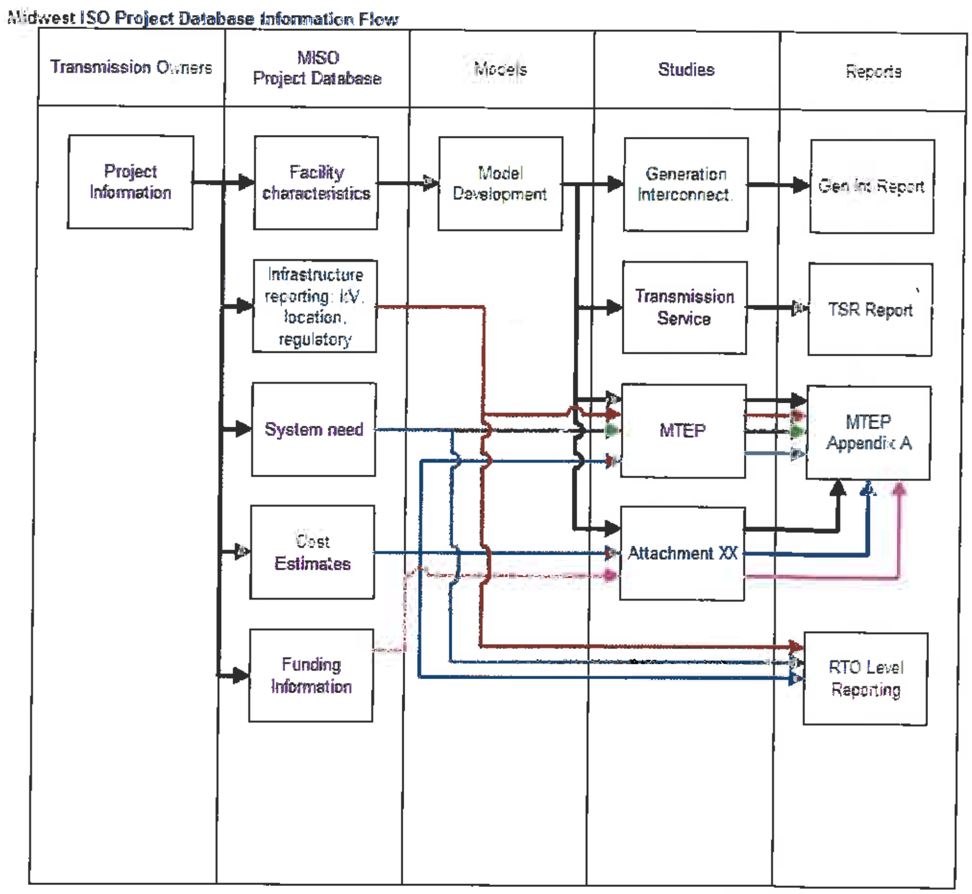


Figure 4.2-1 MISO Projects Database Information Flow

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.

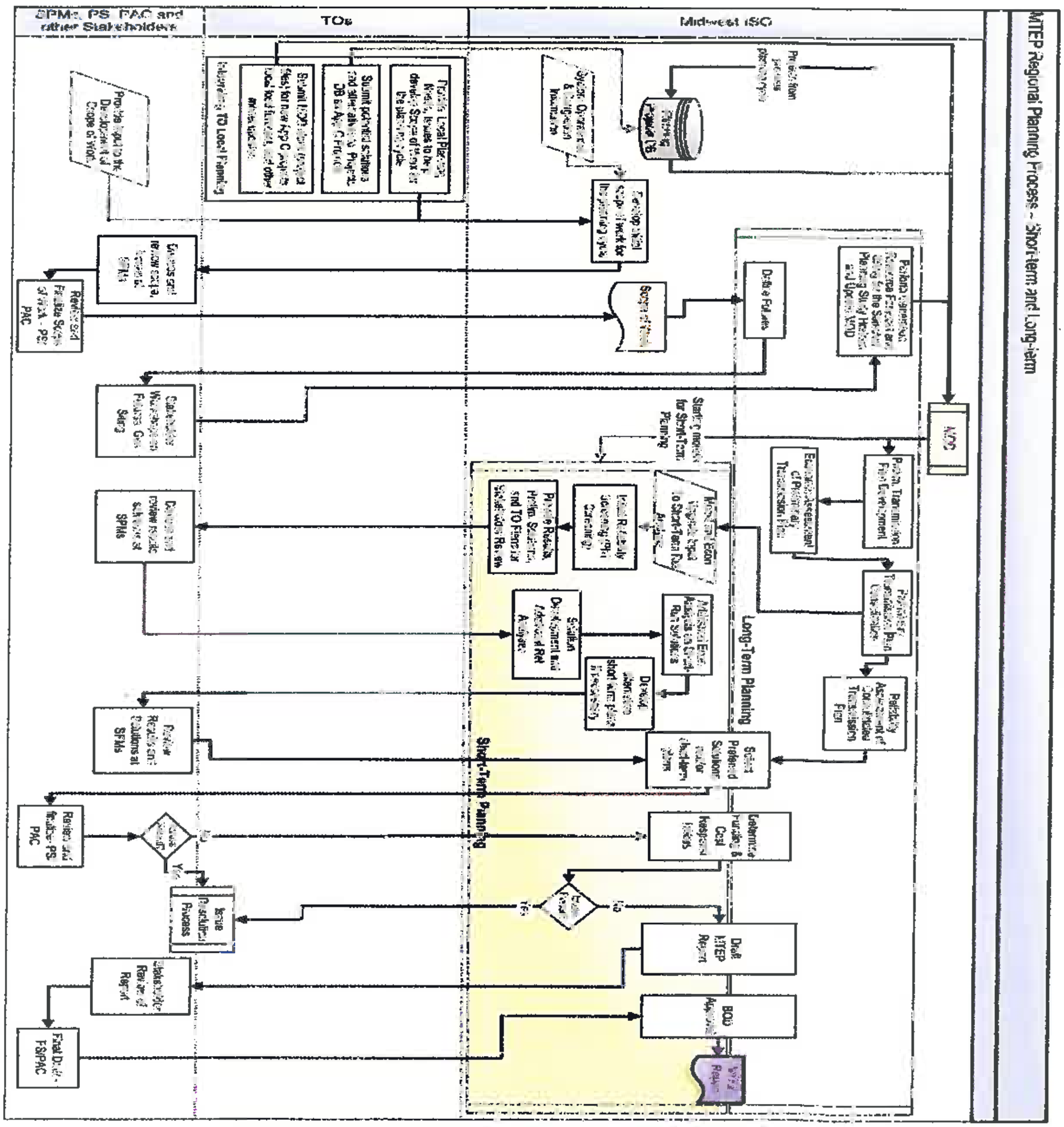


Figure 4.2-2 – MTEP Regional Planning Process – Short-term and Long-term

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

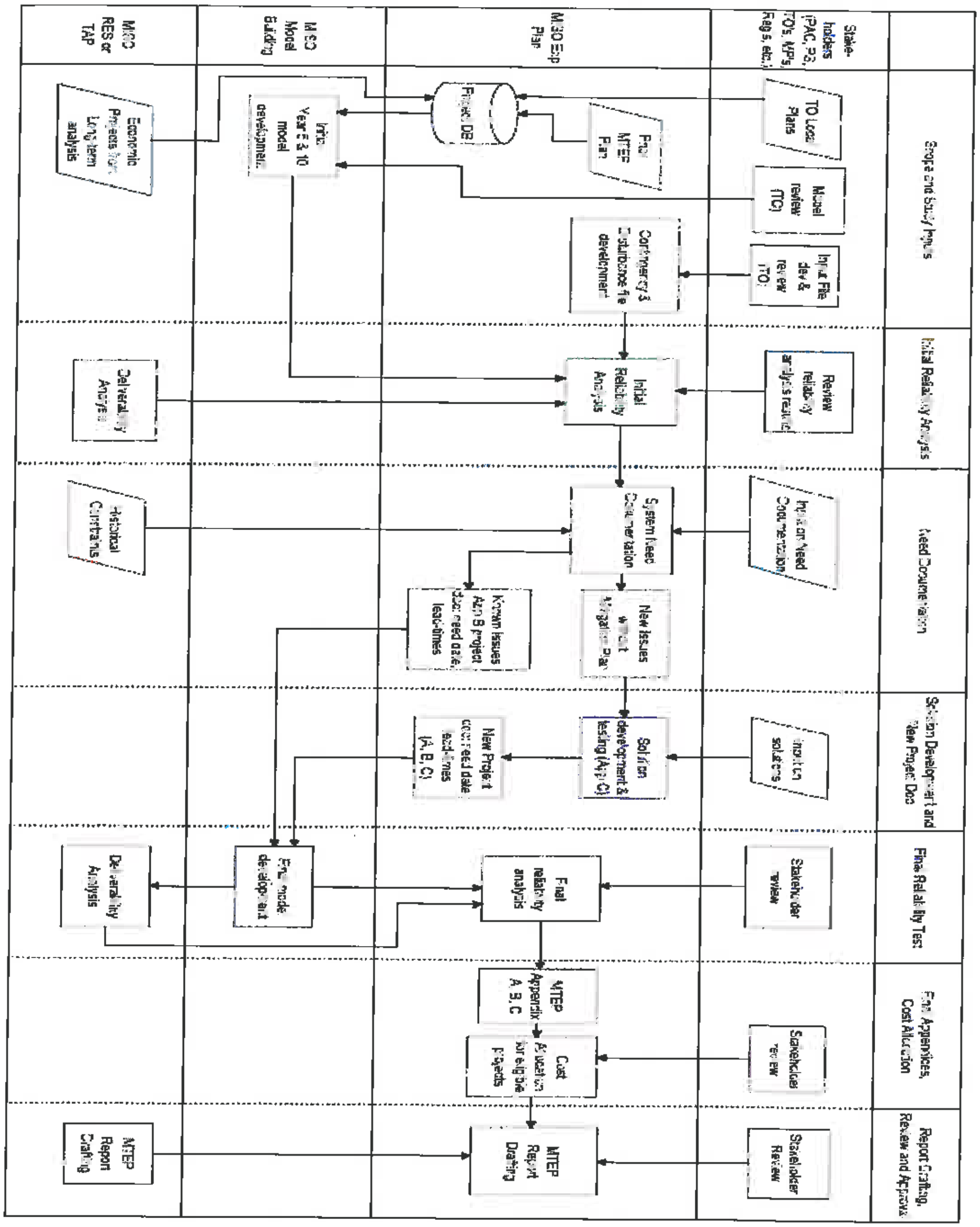
Figure 4.3-1 below shows the process flow diagram for the short-term planning analysis. The initial phase of the analysis documents the system issues driving projects in the MISO MTEP Projects database. This initial analysis identifies Transmission Compliance Issues and Transmission Value Issues driving 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 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.

4.3.5 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.

4.3.5.1 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.

4.3.5.2 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.

4.3.6 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.

4.3.7 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.

4.3.7.1 Steady-State Analysis

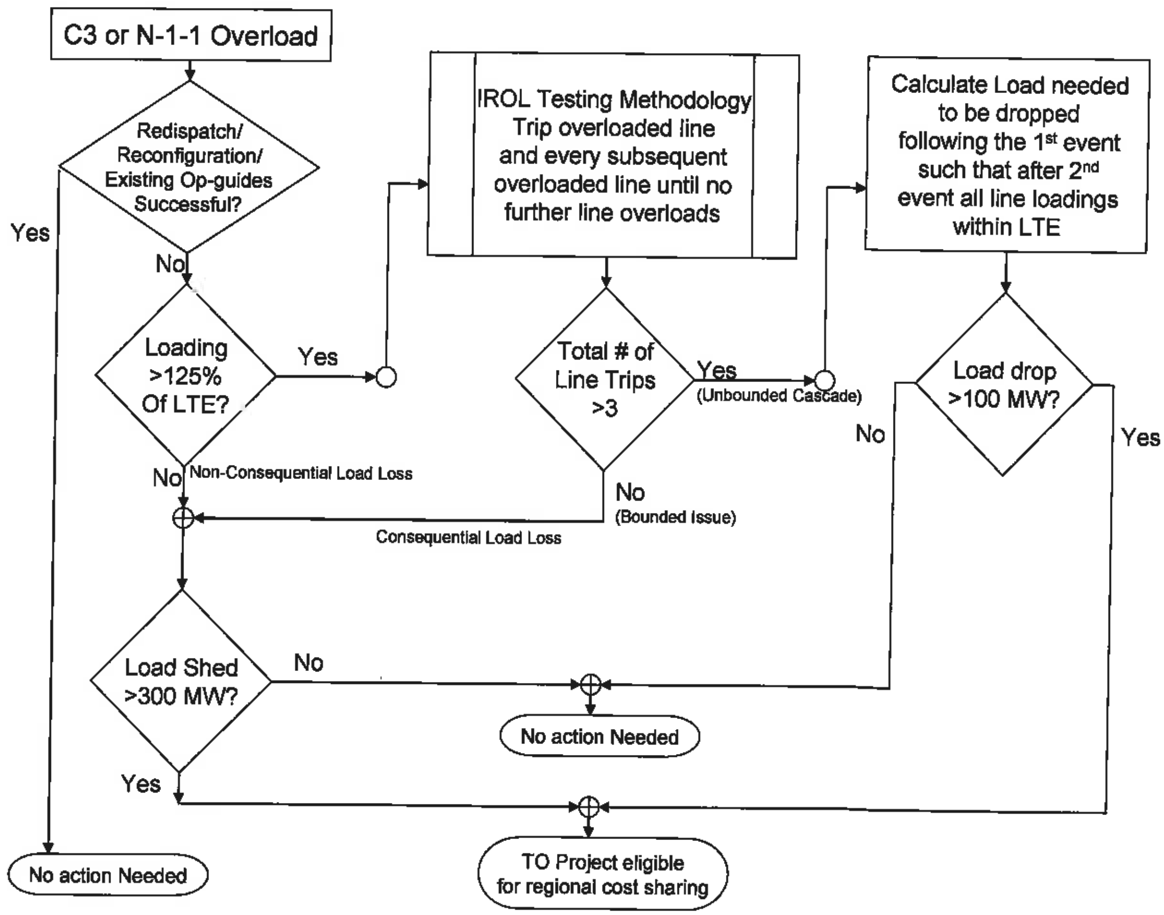
Steady-state Contingency Analysis will be performed on the initial planning models to test the contingencies of various categories described under Section 4.3.6 above. Thermal and voltage violations will be screened based on the applicable regional or local thresholds for a given condition and equipment.

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.

Review Methodology Thermal Cascading for C3 Events

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.

4.3.7.2 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

4.3.7.3 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	$0.7 \le V_{bus} \le 1.2$	$0.9 \le V_{bus} \le 1.1$	Line_loading ≤1.1*rateB Trx_loading ≤1.25*rateB	West With Fault: $\zeta_i \ge 0.0081633$ No fault line trip: $\zeta_i \ge 0.0167660$ **MISO criteria**: $\zeta_i \ge 0.03$	Not to be less than **25%** (Canada-U.S interface, see note 10)
C	$0.7 \le V_{bus} \le 1.2$	$0.9 \le V_{bus} \le 1.1$	Line_loading ≤1.1*rateB Trx_loading ≤1.25*rateB	West With Fault: $\zeta_i \ge 0.0081633$ No fault line trip: $\zeta_i \ge 0.0167660$ **MISO criteria**: $\zeta_i \ge 0.03$	Not to be less than 25% (Canada-U.S interface, see note 10)
D	Nothing in addition to NERC requirements				

4.3.7.4 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.

4.3.7.5 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.

4.3.7.6 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.

4.3.8 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.