MTEP17

MISO Transmission Expansion Plan

MISO

MTEP17 REPORT

Book 1

December 2017

Table of Contents

Book 1 / Transmission Studies

Section 2: MTEP Overview

2.1 Investment Summary

The 354 MTEP17 new Appendix A projects represent $2.7 billion[1] in transmission infrastructure investment and fall into the following categories:

- **77 Baseline Reliability Projects (BRP) totaling $957 million**— BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **23 Generator Interconnection Projects (GIP) totaling $238 million** — GIPs are required to reliably connect new generation to the transmission grid.
- **248 Other Projects totaling $1.4 billion** — Other projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects.
- **1 Market Efficiency Project (MEP) totaling $130 million**
- **5 Targeted Market Efficiency Projects (TMEP) totaling $4.9 million of MISO cost responsibility**

The largest 10 projects represent 28 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

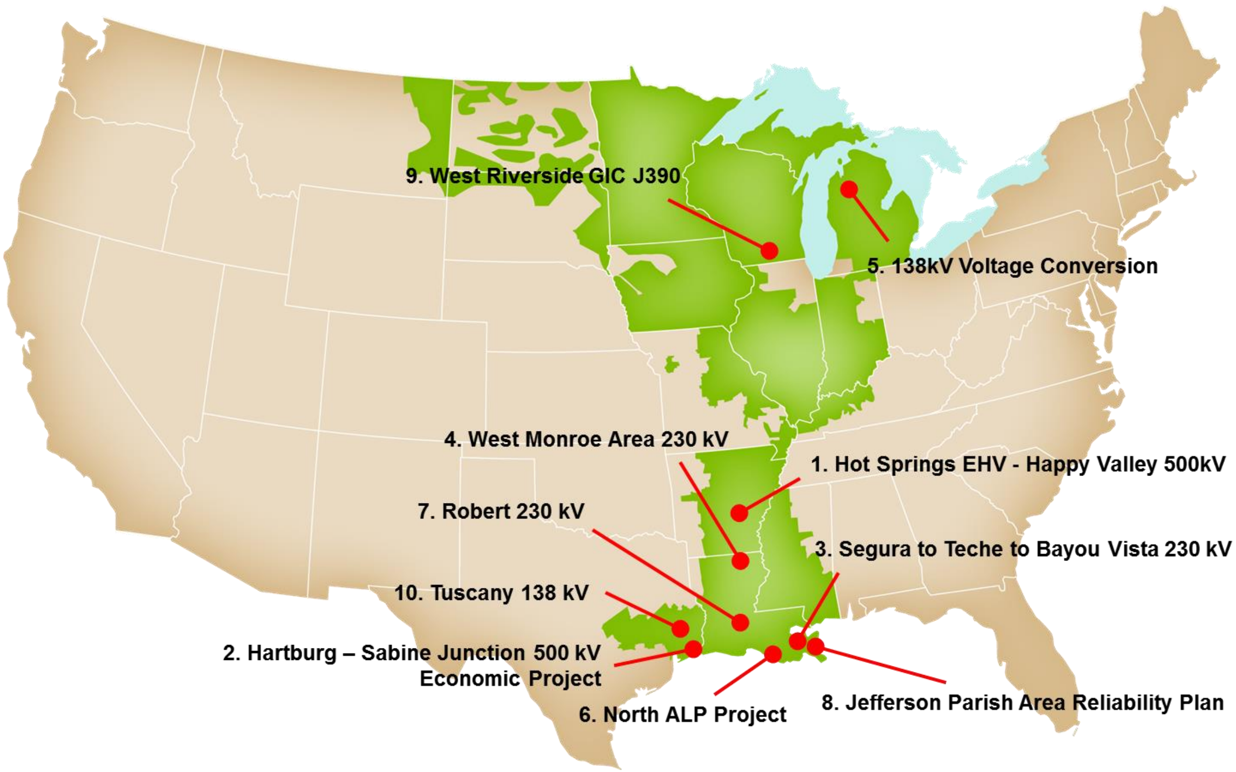


Figure 2.1-1: Top 10 MTEP17 new Appendix A projects (in descending order of cost)

[1] The MTEP17 report and project totals reflect all project approvals during the MTEP17 cycle, including those approved on expedited project review basis prior to December 2017.

The new projects recommended for approval in MTEP17 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP17 Appendix A contain 14 cost-shared Generator Interconnection Projects. Cost sharing information is provided in Chapter 2.2.

MISO Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Market Efficiency (MEP)	Targeted Market Efficiency (TMEP)	Other	Total
Central	$65,432,673				$320,794,000	**$386,226,673**
East	$53,193,017	$12,396,000		$4,918,500	$341,440,000	**$411,947,517**
South	$772,494,866	$31,440,000	$129,679,192		$343,569,235	**$1,277,183,293**
West	$65,847,908	$193,779,548			$410,943,386	**$670,570,842**
Total	**$952,708,630**	**$237,615,548**	**$129,679,192**	**$ 4,918,500**	**$1,393,449,612**	**$2,745,928,325**

Table 2.1-1: MTEP17 New Appendix A investment by project category and planning region

Other Project Type

Within the Other project type, there are a number of subtypes that give more insight into the purpose of these projects (Figure 2.1-2). The majority of Other projects address reliability issues — either due to aging transmission infrastructure, or local non-baseline reliability needs that are not dictated by NERC standards. The remaining projects mostly address distribution concerns, with a small percentage of projects targeting localized economic benefits or line relocations to accommodate other infrastructure.

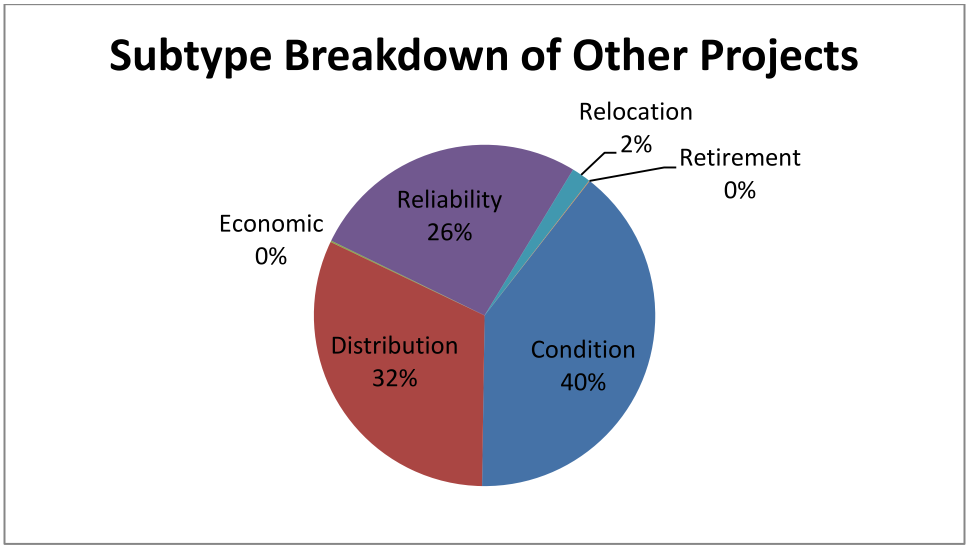


Figure 2.1-2: Subtype breakdown of new MTEP17 Appendix A Other projects

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, circuit breakers or various types of transmission lines (Figure 2.1-3). The majority of facility investment in this cycle based on facility estimated cost is 58 percent, is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements, or new transformers. Twenty-three percent of MTEP facility costs go toward line upgrades including rebuilds, conversions and relocations. Only about 19 percent of facility costs are dedicated to new lines on new right-of-way across the MISO footprint.

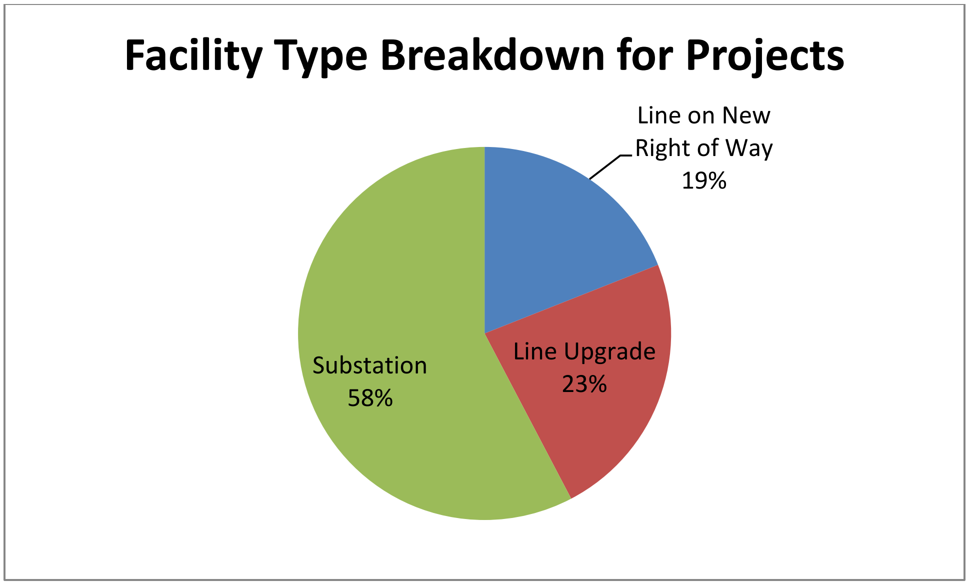


Figure 2.1-3: Facility type for new MTEP17 Appendix A projects

New Appendix A projects are spread over 14 states, with nine states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing capacity in other parts of the system is consumed and new build becomes necessary.

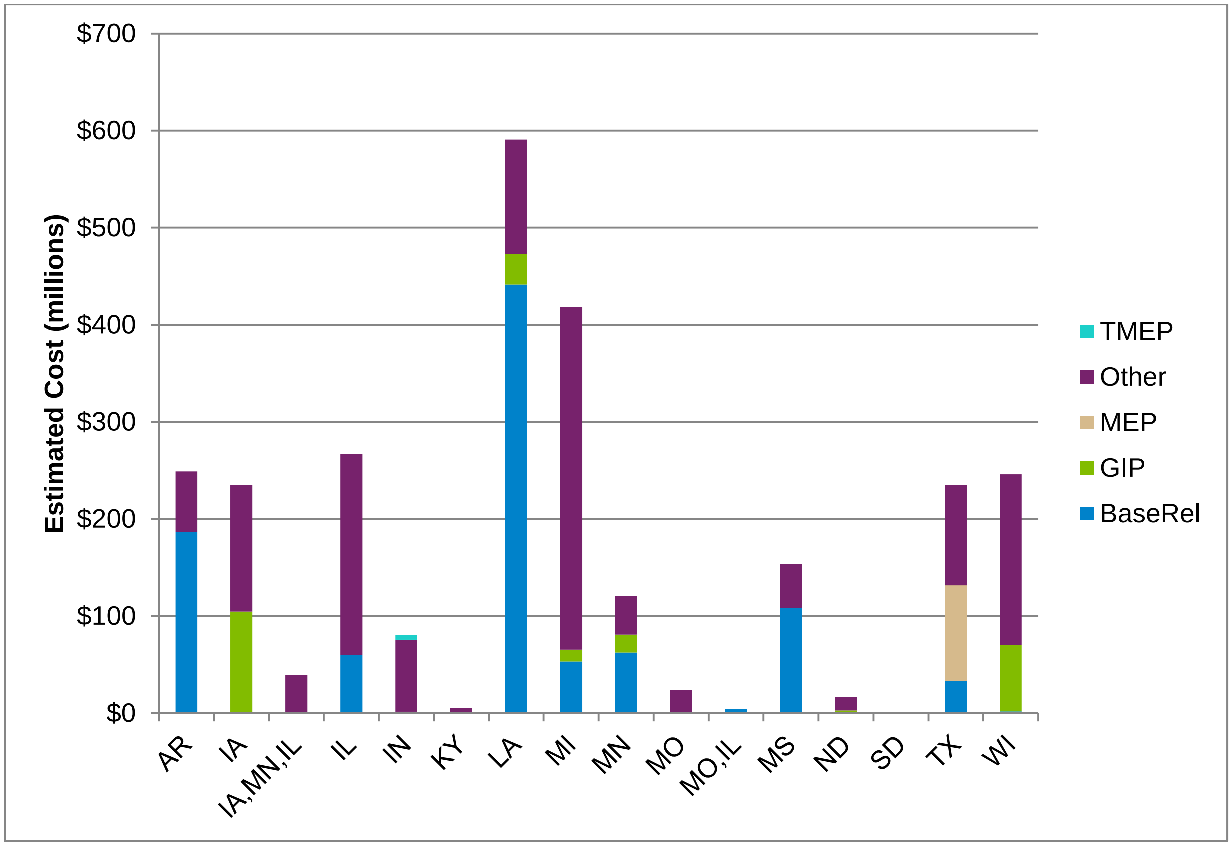


Figure 2.1-4: New MTEP17 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP17 new projects, increases to 1011 projects amounting to approximately $13 billion of investment through the next 10 years (Figure 2.1-5). MTEP17 Appendix A contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Large project investment is shown in a single year but often occurs over multiple years (Figure 2.1-6). Investment totals by year assume that 100 percent of a project's investment is fulfilled when the facility goes into service. It does not reflect projected cash flow or the fact that certain components of a project may be placed in service as a project progresses.

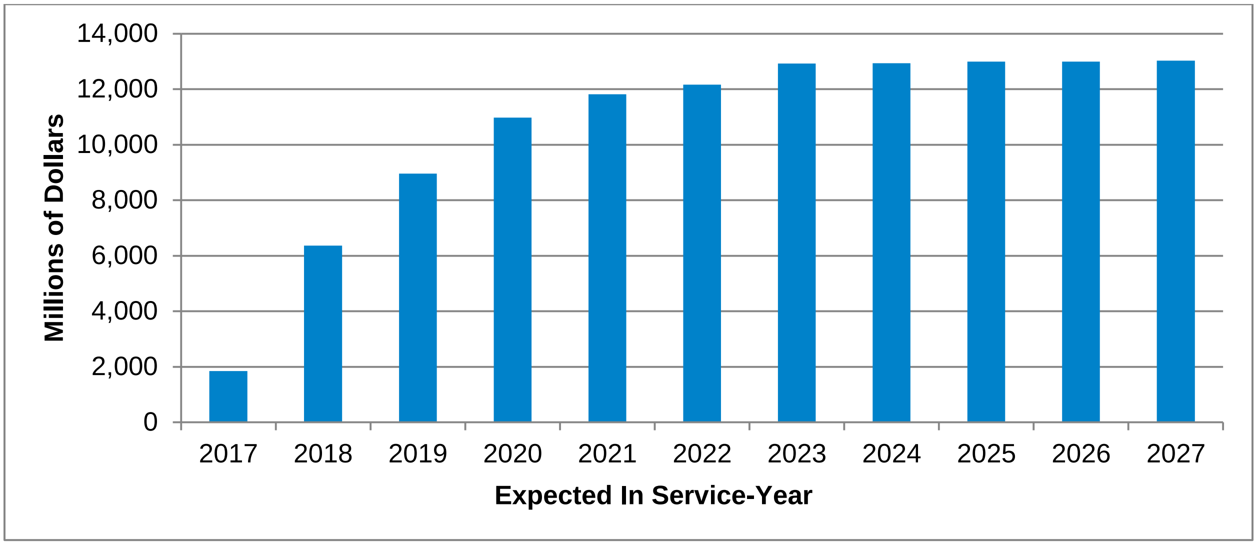


Figure 2.1-5: MTEP17 Appendix A projected cumulative investment by year

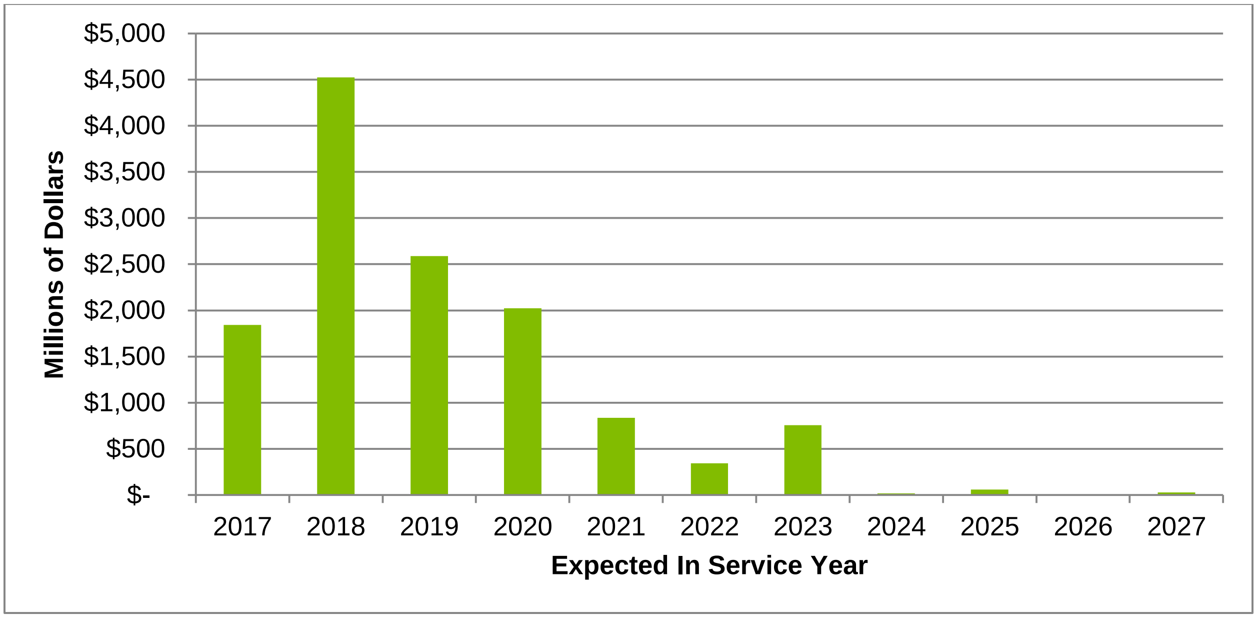


Figure 2.1-6: MTEP17 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[2] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $13.4 billion with another $3.3 billion in Appendix B. New MTEP17 Appendix A projects represents $2.7 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $5.1 billion of the $13 billion in cumulative Appendix A is from the Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the four MISO geographic planning regions: East, Central, West and South (Figure 2.1-7).

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost	Number of Appendix B Projects	Appendix B Estimated Cost
Central	214	$2,460,725,199	92	$125,509,424
East	207	$1,879,822,867	40	$527,358,000
South	214	$3,066,486,731	59	$911,943,663
West	381	$5,988,542,807	82	$1,731,997,915
Total	**1016**	**$13,395,577,604**	**273**	**$3,296,809,002**

Table 2.1-2: Projected transmission investment by planning region

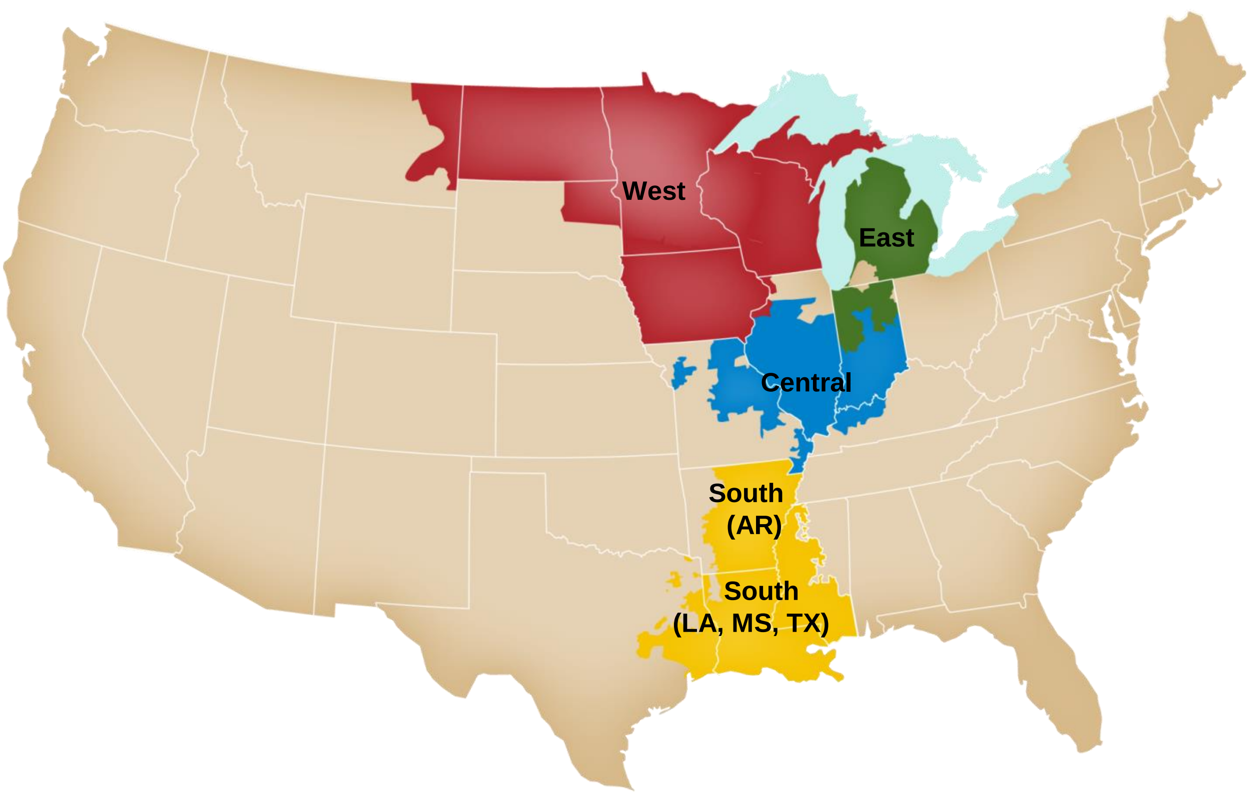


Figure 2.1-7: MISO footprint and planning regions

[2] https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Current%20Members%20by%20Sector.pdf

Active Appendix A Line Miles Summary

MISO has approximately 68,500 miles of existing transmission lines. There are approximately 6,129 miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in MTEP17 Appendix A (Figure 2.1-8, Table 2.1-3).

- 3,500 miles of upgraded transmission line on existing corridors are planned
- 2,600 miles of new transmission line on new corridors are planned

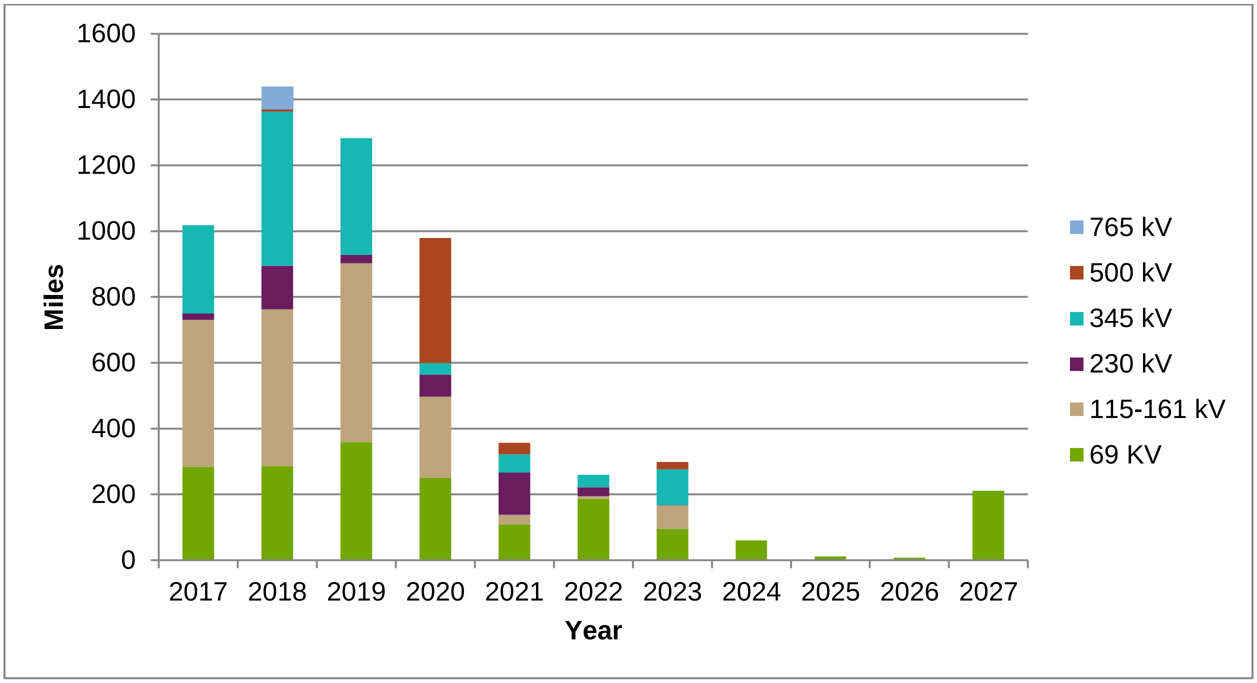


Figure 2.1-8: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2027

Year	69 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2017	284	446	20	269	0		1,019
2018	286	477	132	469	7	69	1,439
2019	359	544	26	355	0		1,283
2020	250	247	67	35	380		979
2021	109	29	128	55	35		356
2022	186	8	27	39			260
2023	96	71	1	109	22		298
2024	60	0					60
2025	11	0					11
2026	8	0					8
2027	211	0					211
Grand Total	**1,859**	**1,822**	**400**	**1,330**	**444**	**69**	**5,924**

Table 2.1-3: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2027

2.2 Cost Sharing Summary

New MTEP17 Appendix A Cost-Shared Projects

MTEP17 recommends a total of 20 new cost-shared projects, with a total shared project cost of $185 million for inclusion in Appendix A. The 20 cost-shared projects include:

- 14 Generator Interconnection Projects (GIP) with a total project cost of $195 million, with $50 million allocated to load and the remaining $145 million allocated directly to generators[3]
- 1 Market Efficiency Project (MEP) with a total project cost of $129.7 million
- 5 Targeted Market Efficiency Projects (TMEP) with a total MISO project cost responsibility of $4.9 million

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment (Chapter 5.1, Table 5.1-1).

Cost allocation methods vary depending on the classification of the project. For GIPs the majority of the costs are allocated to the pricing zone where the project is located.[4] For MEPs, a portion of costs are distributed to Cost Allocation Zones based on the adjusted production cost benefits and the remaining is distributed among the applicable planning area by company load ratio share. TMEPs with PJM are allocated amongst each RTO by the ratio of Day Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO portion is then allocated to the MISO Transmission Pricing Zones using historical nodal load congestion data.

In MTEP17, approximately $117.9 million of the approved costs for GIPs, MEPs, and TMEPs is allocated to the pricing zone where the project is located. The remaining $66.9 million is allocated to neighboring pricing zones or to all pricing zones system-wide (within the applicable planning area).

In MTEP17, approximately $117.9 million of the approved costs for GIPs, MEPs and TMEPs is allocated to the pricing zone where the project is located. The remaining $66.9 million is allocated to neighboring pricing zones or to all pricing zones system-wide (within the applicable planning area). Appendix A-2.3 shows a tabular summary of this information by Transmission Pricing Zone.

Cost Allocation Between Planning Areas For GIPs and MEPs

With the integration of the MISO South region on December 19, 2013, a cost allocation transition period started that determines how approved cost-allocated projects are shared amongst the pricing zones in the MISO North/Central and MISO South planning areas. The transition period concludes when certain Tariff criteria are met, likely at the end of MTEP18.[5] The cost-shared projects in MTEP17 all terminate

[3] Note that the costs indicated as “allocated to generators” does not account for the Transmission Owners who reimburse qualifying generators 100 percent of the costs incurred for Generation Interconnection Projects.
[4] See Chapter 5.1 for more information on project cost allocation.
[5] According to the Tariff: ***Second Planning Area's Transition Period:*** The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period.

exclusively in one planning area, and are cost shared amongst their respective pricing zones (Table 2.2-1).

Type and Location of Project	Approved Before Transition Period		Approved and/or Identified During Transition Period		Approved After Transition Period Ends
	Treatment During Transition Period	Treatment After Transition Period	Treatment During Transition Period	Treatment After Transition Period	
GIPs and MEPs terminating exclusively in one planning area	Within North/Central planning area	Within North/Central planning area	Within applicable planning area	Within applicable planning area	Applicable to both planning areas
GIPs and MEPs terminating in both planning areas	Not Applicable	Not Applicable	Applicable to both planning areas	Applicable to both planning areas	Applicable to both planning areas

Table 2.2-1: Cost-shared GIP and MEP transition period Tariff provisions

Cumulative Summary of All Cost-Shared Projects Since MTEP06

A total of 167 projects have been eligible for cost sharing since cost-sharing methodologies were first incorporated into the MTEP process. Cost sharing began in 2006 with Baseline Reliability Projects[6] (BRP) and GIPs, and was later augmented with MEPs in 2007 and Multi-Value Projects (MVP) in 2010. Starting with MTEP13 and going forward, the costs for BRPs were removed from cost sharing and allocated to the pricing zone of the project location. The cost-shared eligible projects represent $11.1 billion in transmission investment, including portion of project costs allocated directly to generators for GIPs (Figure 2.2-1, Table 2.2-2). The distribution of cost-shared projects includes:

- Baseline Reliability Projects (BRP) — 75 projects, $3.4 billion
- Generation Interconnection Projects (GIP) — 87 projects, $721 million (including the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — 5 projects, $322.6 million
- Multi-Value Projects (MVP) — 17 projects, $6.65 billion
- Targeted Market Efficiency Projects (TMEP) – 5 projects, $4.9 million (MISO share of project cost only)

[6] For Baseline Reliability Projects effective June 1, 2013, all project costs are allocated to the pricing zone where the project is located.

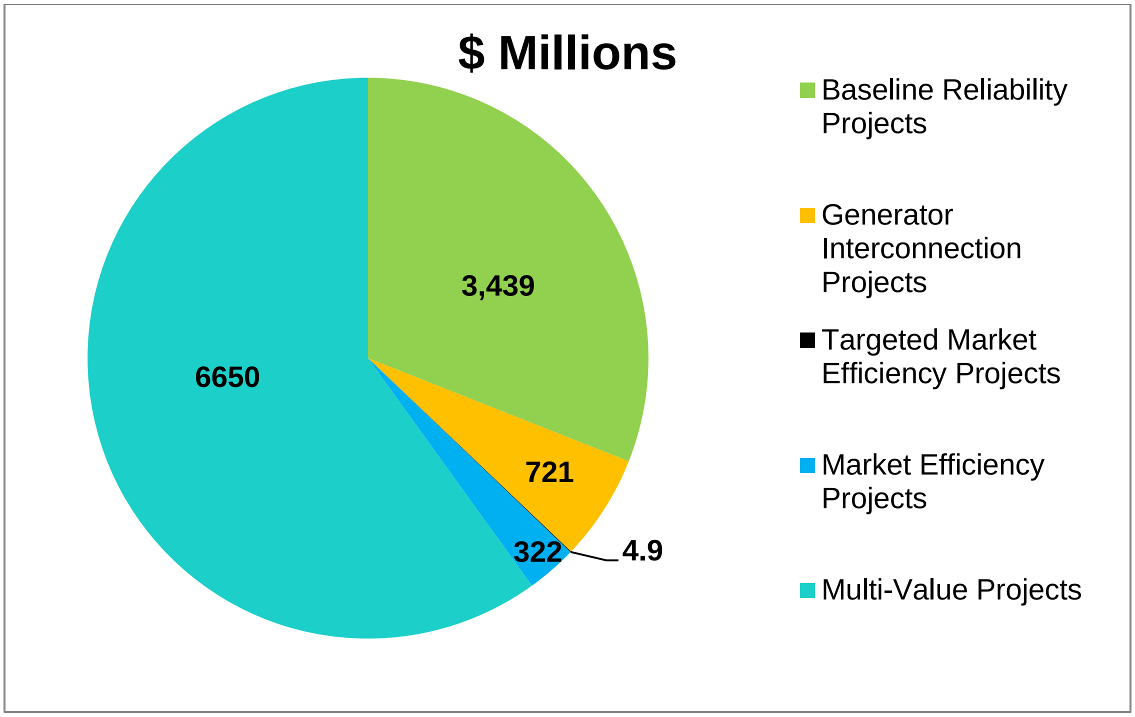


Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

Cost-Shared Project Type	BRP ($M)	GIP ($M)	MEP ($M)	TMEP ($M)	MVP ($M)	Total ($M)
A in MTEP06	$620.1	$72.9	$0.0	$0.0	$0.0	**$693.0**
A in MTEP07	$182.9	$34.4	$0.0	$0.0	$0.0	**$217.3**
A in MTEP08	$1,589.6	$21.8	$0.0	$0.0	$0.0	**$1,611.4**
A in MTEP09	$167.6	$107.9	$5.6	$0.0	$0.0	**$281.1**
A in MTEP10	$41.3	$4.2	$0.0	$0.0	$504.0	**$549.5**
A in MTEP11	$399.5	$86.2	$0.0	$0.0	$6,146.0	**$6,631.7**
A in MTEP12	$438.5	$53.4	$12.0	$0.0	$0.0	**$503.9**
A in MTEP13	$0.0	$8.0	$0.0	$0.0	$0.0	**$8.0**
A in MTEP14	$0.0	$35.4	$0.0	$0.0	$0.0	**$35.4**
A in MTEP15	$0.0	$22.9	$67.4	$0.0	$0.0	**$90.3**
A in MTEP16	$0.0	$78.6	$108.0	$0.0	$0.0	**$186.6**
A in MTEP17	$0.0	$195.7	$129.7	$4.9	$0.0	**$330.3**
Total	**$3,439.5**	**$721.4**	**$322.7**	**$4.9**	**$6,650.0**	**$11,138.5**

Table 2.2-2: MTEP06 to MTEP17 cost-shared project costs by MTEP cycle and project type (shown in $millions)

For the approved portfolio of MVPs, the costs are allocated 100 percent region-wide (North/Central only) and recovered from customers through a monthly energy charge that is calculated using the applicable monthly MVP Usage Rate. The MVP charge applies to all MISO load and export and through transactions sinking outside the MISO region. However, the MVP charge does not apply to load under grandfathered agreements.

Indicative annual MVP Usage Rates[7] (dollar per MWh) are based on the approved MVP portfolio using current estimated project costs and in-service dates. The MVP usage rates have been calculated for the period 2018 to 2054 and are shown by the blue line (Figure 2.2-2).[8] The red and green lines represent an average of the estimated MVP Usage Rates over 20 and 40 year periods. For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.87 per month over the next 20 years.

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.87 per month over the next 20 years.

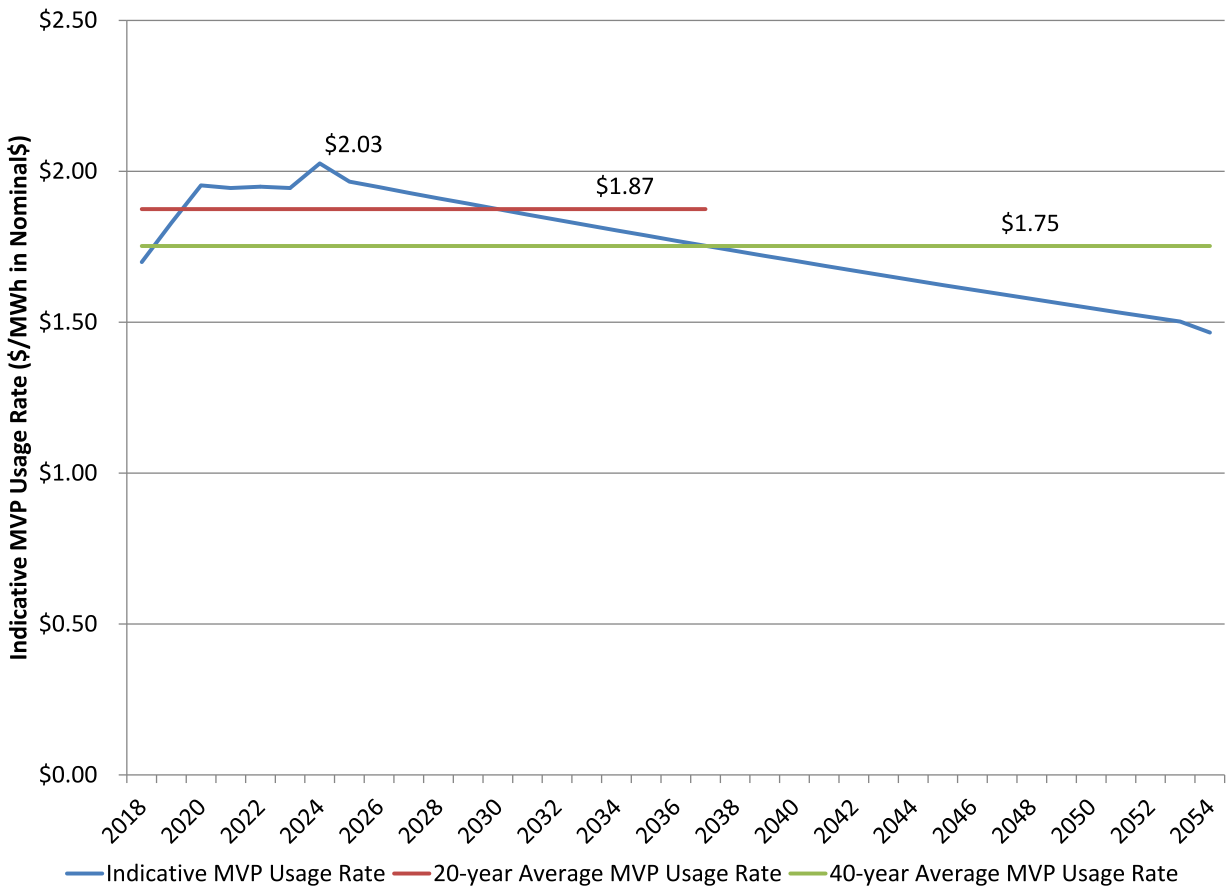
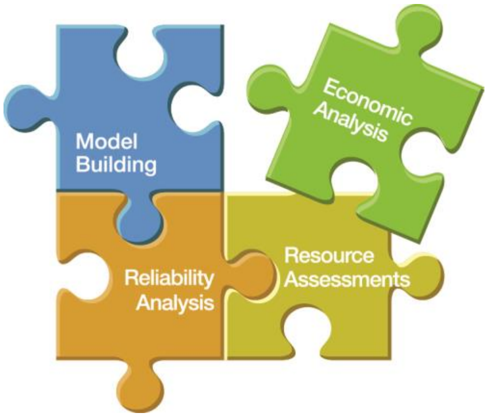


Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2017 to 2054

[7] The MVP Usage Rate is charged via Schedule 26-A to: 1) Export and Through-Schedules; and 2) Monthly Net Actual Energy Withdrawals, excluding those Monthly Net Actual Energy Withdrawals provided under GFAs. For Withdrawing Transmission Owners with obligations for approved Multi-Value Projects those charges are recovered through Schedule 39.

[8] The annual estimated MVP Usage Rates for 2017 to 2054 shown in Figure 2.2-2 are included in Appendix A-3. Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO website at the following URL under the MTEP Study information section: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

2.3 MTEP17 Process and Schedule



This MTEP report is the result of 18 months of in-depth research and analysis to create a comprehensive plan for transmission expansion. Each MTEP cycle entails model-building, stakeholder input, reliability analysis, economic analysis, resource assessments and report writing to create a list of recommended projects, which are listed in MTEP Appendix A. It requires many interactions between various work streams and stakeholders (Figure 2.3-1).

The process ends when this report and a list of projects in Appendix A to go before MISO's Board of Directors December meeting for official approval.

At its most basic level MTEP is MISO's annual process to study and recommend transmission expansion projects for inclusion in MTEP Appendix A. Along the way, the process includes sub-deliverables such as Planning Reserve Margins, resource forecasts, regional policy studies and interregional studies.

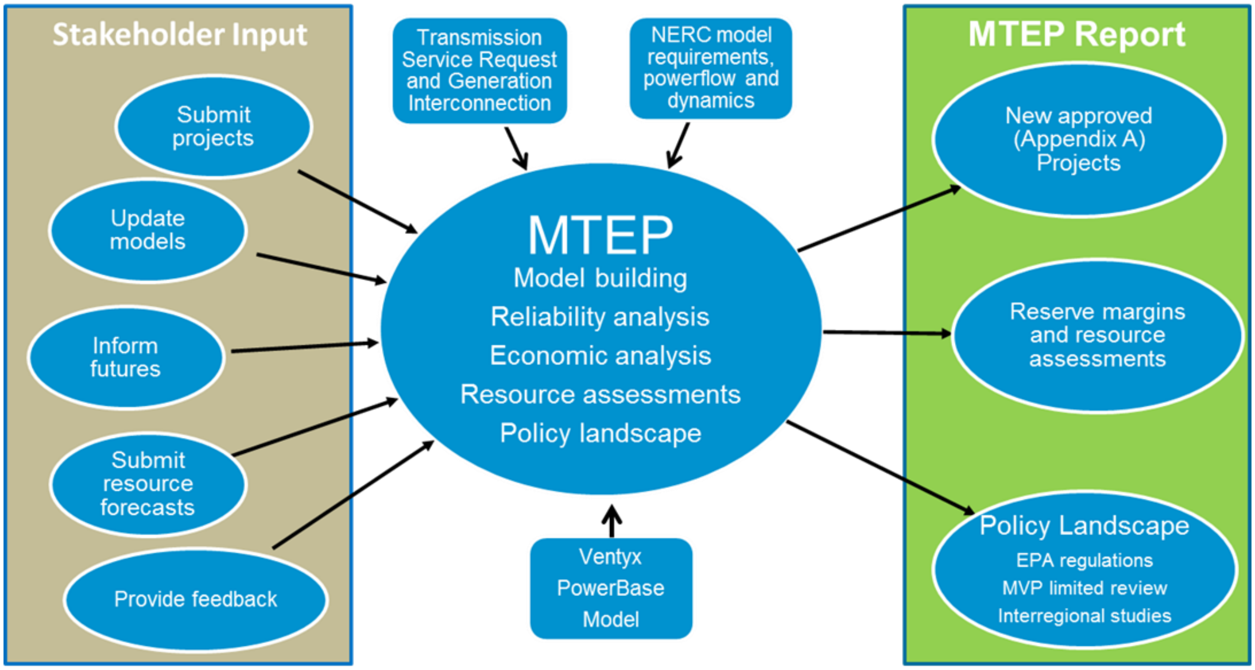


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

MISO incorporates multiple perspectives by conducting reliability and economic analyses from the bottom up and top down. It evaluates long-term transmission service requests (TSR) to move energy in, out, through or within the MISO market footprint, and generator requests to connect to the grid via the Generator Interconnection Queue. MTEP also reports on studies that address public policy questions (Figure 2.3-2).

Figure 2.3-2: MISO's value-based planning approach

MTEP17 Workstreams

Completion of MTEP17 requires coordination between multiple subject-matter experts and different types of analyses (Figure 2.3-3). It integrates reliability, transmission access, market efficiency, public policy and other value drivers across all planning horizons.

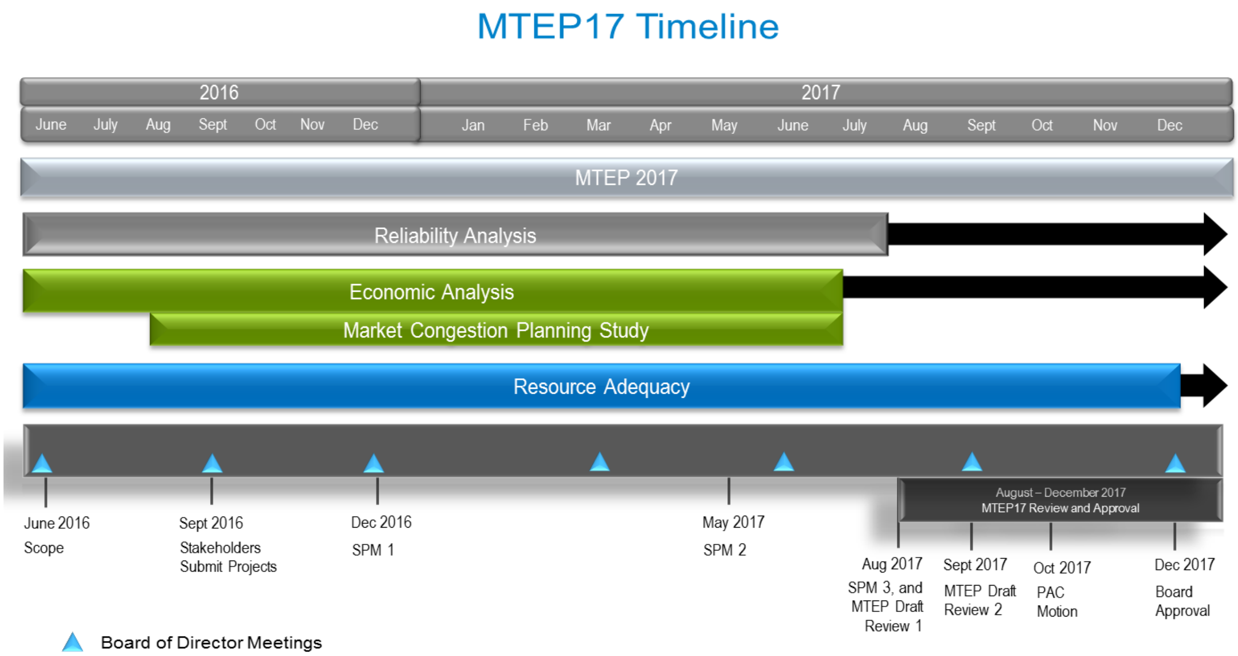


Figure 2.3-3: MTEP17 timeline

Stakeholder Involvement in MTEP17

Stakeholders provide model updates, project submissions, input on appropriate assumptions, review the results and comment on report drafts. This feedback occurs through a series of stakeholder forums. Each of the four MISO subregions hold Subregional Planning Meetings (SPM) at least three times annually (per FERC Order 890 requirements) to review projects specific to its region. MISO staff and stakeholders review system needs for each project. Some projects may also use stakeholder Technical Study Task Forces (TSTF) to discuss analytical results in greater detail or when these results are Critical Energy Infrastructure Information (CEII). The SPMs report up to the Planning Subcommittee (PSC). The Planning Advisory Committee (PAC) reviews the full MTEP report in detail, and provides formal feedback to the System Planning Committee (SPC), which is made up of members of the MISO Board of Directors. The SPC makes its recommendations to the full Board, which has final approval authority (Figure 2.3-4).

Figure 2.3-4: MTEP stakeholder forums

MTEP17 Schedule

Each MTEP cycle spans 18 months. MTEP17 began June 2016 and ends December 2017, with Board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP17 projects	September 2016
First round of Subregional Planning Meetings (SPM)	December 2016
Second round of Subregional Planning Meetings (SPM)	May 2017
MTEP17 Report first draft posted	August 2017
Third round of SPM meetings	August 2017
Planning Advisory Committee final review and motion	October 2017
MISO Board System Planning Committee review	November 2017
MISO Board of Directors meeting to consider MTEP17 approval	December 2017

Table 2.3-1: MTEP17 schedule, major milestones

A Guide to MTEP Report Outputs

The MTEP17 report is organized into four books and a series of detailed appendices.

- Book 1 summarizes this cycle's projects and the analyses behind them
- Book 2 describes annual and targeted analyses for Resource Adequacy — including Planning Reserve Margin (PRM) requirement analysis and Long Term Resource Assessments
- Book 3 presents Policy Landscape. It summarizes regional studies and interregional studies.
- Book 4 presents additional regional energy information to show a more complete picture of the regional energy system
- Appendices A through F provide the detailed project information, as well as detailed assumptions, results and stakeholder feedback

2.4 MTEP Project Types and Appendix Overview

MTEP Appendices A and B contain the projects vetted by MISO through the planning process. The appendices in the MTEP report indicate the status of a given project in the MTEP review process.

Appendix A contains projects approved by the MISO Board of Directors, thereby creating a good-faith obligation for the Transmission Owner to build it.

Appendix B lists projects with a documented need and anticipated effectiveness, but that are not yet ready for execution. A move from Appendix B to Appendix A is the most common progression through the appendices; however projects may remain in Appendix B for a number of planning cycles.

Appendix A includes projects from prior MTEPs that are not yet in service, as well as new projects recommended to the MISO Board of Directors for approval in this cycle. Find the newest projects in the Appendix A spreadsheet by looking for "A in MTEP17" in the "Target Appendix" field.

There are three distinct categories of transmission projects:

- Bottom-Up Projects
- Top-Down Projects
- Externally Driven Projects

The specific types of transmission projects include:

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

Specific transmission project types align to their parent transmission project categories (Table 2.4-1).

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

Table 2.4-1: Transmission project type-to-category mapping

Bottom-Up Projects

Bottom-up projects — transmission projects classified as Other projects and Baseline Reliability Projects — are not cost shared and are generally developed by Transmission Owners. MISO will evaluate all bottom-up projects submitted by Transmission Owners and validate that the projects represent prudent solutions to one or more identified transmission issues.

- **Baseline Reliability Projects (BRP)** are required to meet North American Electric Reliability Corp. (NERC) standards. Since MTEP13, Baseline Reliability Projects are no longer cost shared.
- **Other Projects** address a wide range of project drivers and system needs. Some of these drivers may include local reliability needs; economic benefits and/or public policy initiatives; or projects that are not a part of the bulk electric system under MISO functional control. Because of this variety, Other projects are generally classified in one of the following sub-types: Clearance, Condition, Distribution, Economic, Local Multiple Benefit, Metering, Operational, Performance, Reconfiguration, Relay, Reliability, Relocation, Replacement or Retirement.

Top-Down Projects

Top-down projects are transmission projects classified as Market Efficiency Projects and Multi-Value Projects. Regional or sub-regional top-down projects are developed by MISO working in conjunction with stakeholders to address regional economic and/or public policy transmission issues. Interregional top-down projects are developed by MISO and one or more additional planning regions in conjunction with stakeholders to address interregional transmission issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or MISO Tariff, first between MISO and the other planning regions, then within MISO based on provisions in Attachment FF of the MISO Tariff.

- **Multi-Value Projects (MVP)** meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.
- **Market Efficiency Projects (MEP)**, formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as MEPs based on cost and voltage thresholds and are developed to produce a benefit to cost ratio in excess of 1.25.

Externally Driven Projects

Externally driven projects are projects driven by needs identified through customer-initiated processes under the MISO Tariff. Externally driven projects are Generation Interconnection Projects, Transmission Delivery Service Projects and Market Participant Funded Projects.

- **Generation Interconnection Projects (GIP)** are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all network upgrades associated with GIPs are eligible for cost sharing between pricing zones.
- **Transmission Delivery Service Project (TDSP)** projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.
- **Market Participant Funded Projects** represent transmission projects that provide benefits to one or more market participants but do not qualify as Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects. These projects are not cost shared through the MISO Tariff. Their construction is assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Transmission Owners Agreement upon execution of the applicable agreement(s).

MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by MISO staff and approved by the MISO Board of Directors for implementation by Transmission Owners.[9]

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[10]. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards, while others may be required to provide distribution interconnections for load-serving entities. Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also decrease resource adequacy requirements through reduced losses during system peak or reduced planning reserve needs. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency standards. All projects in Appendix A address one or more MISO-documented transmission needs. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

Projects must go through a specific process to move into Appendix A. MISO staff must:

- Review the projects via an open stakeholder process at Subregional Planning Meetings
- Validate that the project addresses one or more transmission needs
- Consider and review alternatives
- Consider and review planning-level costs
- Endorse the project
- Verify whether the project is qualified for cost sharing as a Generation Interconnection Project, Market Efficiency Project or Multi-Value Project per provisions of Attachment FF or if it will be participant-funded
- Hold a stakeholder meeting to review a project or group of projects in which costs can be shared, or other major projects for zones where 100 percent of costs are recovered under the Tariff
- Take the new projects to the Board of Directors for approval. Projects may move to Appendix A following a presentation at any regularly scheduled board meeting

The MTEP Active Project List is periodically updated and posted as projects go through the MTEP process and are approved. Projects generally move to Appendix A in conjunction with the annual approval of the MTEP report. In addition to the regular annual approval process, under specific circumstances, recommended projects need not wait for completion of the next MTEP for MISO Board of Directors approval and inclusion in Appendix A, but can go through an expedited project review process.

MTEP Appendix B

MTEP Appendix B contains all bottom-up projects validated by MISO as a solution to address an identified system need, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead time and there is still some uncertainty around the project drivers (such as changes in the projected conditions) or potential alternatives are still being considered. MTEP Appendix B is limited to bottom-up projects only (Baseline Reliability Projects and Other Projects) and the projects will be reviewed by MISO in subsequent cycles to ensure the system needs still exist or a preferred solution is identified.

[9] Projects with a Target Appendix A in the current MTEP cycle are not officially placed into Appendix A until Board of Directors approval in December of the cycle year.

[10] http://www.nerc.net/standardsreports/standardssummary.aspx

2.5 MTEP17 Model Development

Transmission system models are the foundation of the MTEP analytical processes. The viability of the study results hinges on the accuracy of the models used. Planning model development at MISO is a collaborative process with significant stakeholder interaction and neighbor coordination. Stakeholders provide modeling data, help develop assumptions for modeling future transmission system scenarios and review the models. MTEP models are also coordinated with MISO's neighboring entities and their system representation is updated based on their feedback.

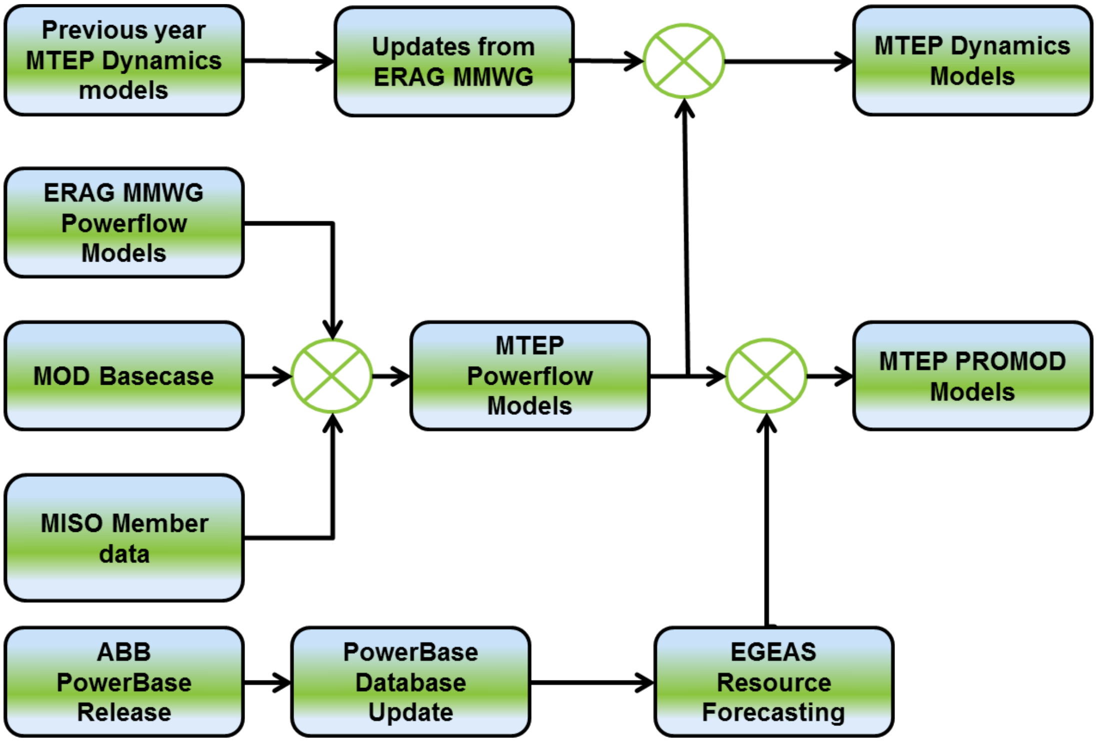
MTEP17 model-building continues MISO's submittal of modeling data to Eastern Interconnection model development per MOD-032-1

The MTEP16 model development process underwent some changes in data submission obligations per NERC Standard MOD-032-1 with inclusion of generator owners and load-serving entities, which continues as part of the MTEP17 model development process. In addition to NERC Standard TPL-001-4 requirements, MISO built a powerflow and dynamics model suite to support the Eastern Interconnection modeling process per MOD-032 requirements. For the MTEP planning process, two sets of powerflow models are built. One model set contained approved future projects from MTEP16 Appendix A called Appendix A Only models. The other model set contained approved MTEP16 Appendix A projects and projects targeted for approval in MTEP17 called Target A models.

For MTEP studies, models for steady-state powerflow and dynamics stability reliability analyses are built to represent a planning horizon spanning the next 10 years; economic studies represent a 15-year planning horizon. The primary sources of information used to develop the models are:

- MISO's Model on Demand (MOD) powerflow database, which contains existing transmission system data, substation level load profiles, future transmission projects, generator interconnection projects, and transmission service related project information
- MISO members, including Transmission Owners, Generation Owners and Load-Serving Entities
- Eastern Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) series models used for external area representation
- ASEA Brown Boveri (ABB) PROMOD PowerBase database
- External model updates from neighboring planning entities

MTEP models are interdependent (Figure 2.5-1). Figure 2.5-1 shows the major data inputs into the MTEP modeling processes.



ERAG – Eastern Interconnection Reliability Assessment Group. EGEAS – Electric Generation Expansion Analysis System
MMWG – Multi-regional Modeling Working Group. MTEP – MISO Transmission Expansion Plan

Figure 2.5-1: MTEP model relationships

Reliability Study Models - Powerflow Models

MISO developed regional powerflow models for MTEP17 as required by the TPL-001-4 standard and ERAG MMWG process (Table 2.5-1). Developed model base cases and sensitivity cases are listed with the TPL-001-4 requirement[11]. The table includes renewable wind resource levels at percent of nameplate. All models assume solar generation at 50 percent of nameplate.

Model Year	Base case	Sensitivity
Year 2	2019 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2019 Light Load (minimum load level) wind at 0% (*TPL requirement R2.1.4*)
Year 5	2022 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2022 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.1.4*)
Year 5	2022 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.1.2*)	2022 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.1.4*)
Year 5	2022-2023 Winter Peak with wind at 40%	
Year 10	2027 Summer Peak with wind at 15.6% (*TPL requirement R2.2.1*)	

Table 2.5-1: MTEP17 powerflow models

[11] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-001-4_Standard_Application_Guide_endorsed.pdf

Per TPL-001-4 requirement R1.1, the system model contains representations of the following:

- R1.1.1 Existing Facilities: MISO's Model on Demand (MOD) database is used to store modeling data for all the existing facilities. MOD base case is updated monthly in collaboration with MISO members.
- R1.1.2. Known Outages: MISO models any known outage(s) of generation or transmission facility with a duration of at least six months using data from Control Room Operations Window (CROW) Outage Scheduling System.
- R1.1.3. New planned facilities and changes to existing facilities: MOD is also used to capture all the future transmission upgrades and changes to existing facilities, which go into models per their in-service dates. To support MTEP study requirements, two sets of powerflow models were developed:
    - MTEP16 Appendix A Only: These models include only approved future transmission facilities first approved in MTEP16 and future projects approved in prior MTEP studies. Approved future transmission projects also include network upgrades associated with generator interconnection and transmission delivery service requests.
    - MTEP16 Appendix A plus MTEP17 Target Appendix A: These models include future transmission projects approved in Appendix A through prior MTEP studies and new transmission projects submitted for approval in the MTEP17 planning cycle to verify their need and sufficiency in ensuring system reliability.
- R1.1.4. Real and reactive load forecasts: Substation-level real and reactive load is modeled based on seasonal load projections provided by MISO MOD member companies.
- R1.1.5. Known commitments for Firm Transmission Service and Interchange: MISO models known commitments based on Open Access Same-Time Information System (OASIS) information confirmed by both the transacting parties.
- R1.1.6. Resources (supply or demand side) required for load: Resources are modeled based on seasonal projections submitted by members in MOD. All the existing generators are included. Planned generators with signed Generation Interconnection Agreements are included according to their expected in-service dates. Generator retirements that have completed the MISO Attachment Y retirement study process are modeled off-line when unit can be retired.

LBA Generation Dispatch Methodology

The generation dispatch in steady-state powerflow models is done at the Local Balancing Area (LBA) level. Network Resource-type generation is dispatched in an economic order to meet the load, loss and interchange level for each LBA. The area interchange for each LBA is determined by the transaction table agreed upon by transaction participants, and the generation is dispatched to account for the cumulative MISO net area interchange level. LBA generation dispatch includes some energy resources, such as wind and solar, which are dispatched in models in support of renewable energy standards. Wind generation is dispatched at capacity credit level in summer peak models and at average and high levels in off-peak models. The system average wind capacity credit is 15.6 percent based on MISO's Loss of Load Expectation study. Solar generation is dispatched at 50 percent of nameplate. The percentage values for wind generation (Table 2.5-1), are based on the nameplate capacity.

- 15.6 percent represents the wind capacity credit value
- 40 percent represents the average wind output level
- 90 percent represents the high wind output level and transmission design target level
- 40 percent represents the wind output level in the winter model

The LBA dispatch process determines the output of generators and considers several factors such as seasonal output variations, equipment limitations, policy regulations, approved retirements and local operating guides for reliable grid operation. Behind-the-meter generation, hydro machines and non-MISO generation information is retained from generation and load profiles submitted in MOD. Several thousand

MWs of thermal energy resources are not dispatched, wind and solar renewable energy resources are dispatched per study assumptions.

During the model development process, preliminary powerflow models are posted for stakeholder review and comment. MISO planning staff produces a model data check and case summary documents, which are posted for stakeholder review. Stakeholders submit topology corrections back to MISO MOD system for inclusion in subsequent versions of the models.

Generation, load and area interchange data totals for each MISO Local Balancing Area (area) for 2019 summer and 2022 summer peak models are shown in Table 2.5-2. Note that there may be differences in the load values for each area from the Module E load values due to inclusion of station service loads and non-member loads contained within the MISO members' model areas.

Area	2019 Summer Peak (All values in MW)				2022 Summer Peak (All values in MW)			
	Generation	Load	Losses	Area Interchange	Generation	Load	Losses	Area Interchange
HE	1,372	726	34	612	1,369	733	32	605
DEI	7,133	7,456	310	(640)	7,375	7,556	301	(488)
SIGE	1,602	1,451	30	122	1,610	1,460	27	123
IPL	3,758	2,996	76	683	3,758	2,992	75	687
NIPS	3,358	3,748	60	(456)	3,362	3,806	69	(518)
METC	11,170	10,197	353	621	11,515	10,329	362	824
ITCT	11,286	11,908	246	(868)	11,293	11,949	250	(906)
WEC	7,065	6,780	100	173	7,269	6,596	100	306
MIUP	450	514	19	(86)	450	515	19	(87)
BREC	1,397	1,620	20	(241)	1,397	1,617	19	(257)
EES-EMI	4,160	4,030	107	17	4,179	4,088	107	0
EES-EAI	9,059	8,402	201	448	9,271	8,479	190	541
LAGN	2,980	1,752	16	1,212	2,422	1,191	12	541
CWLD	240	394	2	(157)	255	411	2	(159)
SMEPA	1,195	812	15	368	1,275	844	14	417
EES	19,229	19,144	351	(373)	19,527	20,643	342	(700)
AMMO	9,722	8,144	159	1424	10,242	8,184	173	1,887
AMIL	9,742	9,886	237	(381)	9,766	10,052	243	(564)
CWLP	655	425	3	226	655	420	3	231
SIPC	381	315	12	54	461	362	14	119
CLEC	3,608	3,043	72	493	3,681	2,997	75	493
LAFA	197	596	10	(409)	194	623	7	(436)
LEPA	5	229	0	(224)	6	240	0	(235)
XEL	9,232	10,579	264	(1,633)	9,208	12,052	247	(1,884)
MP	1,525	1,418	46	60	1,427	1,823	61	(259)
SMMPA	114	611	1	(498)	137	384	1	(493)
GRE	2,949	2,756	95	96	3,091	1,494	98	111
OTP	2,176	1,693	83	398	2,151	1,876	84	298
ALTW	4,061	4,028	87	(54)	4,091	4,268	90	(62)
MPW	214	161	1	52	223	163	1	58
MEC	6,096	5,847	83	167	6,214	6,184	87	(78)
MDU	419	611	11	(203)	446	701	12	(201)
DPC	841	1,060	40	(259)	844	940	41	(276)
ALTE	3,555	2,860	72	618	3,706	3,199	75	663
WPS	2,458	2,677	50	(273)	2,451	2,715	50	(301)
MGE	265	705	10	(452)	306	708	10	(414)
UPPC	30	214	4	(189)	32	218	4	(190)
Total	**143,698**	**139,786**	**3,279**	**447**	**145,656**	**142,809**	**3,299**	**(604)**

Table 2.5-2: System conditions for 2019 and 2022 models, for each MISO area

Dynamic Stability Models

Dynamic stability models are used for transient stability studies performed as part of NERC TPL assessment and generation interconnection studies. Stability models are required for the study of the TPL-001-4 standard (Table 2.5-3).

Model Year	Base case	Sensitivity
Year 0	2017 Summer Peak with wind at 15.6%	
Year 5	2022 Summer Peak with wind at 15.6% (*TPL requirement R2.4.1*)	2022 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.4.3*)
Year 5	2022 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.4.2*)	2022 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.4.3*)

Table 2.5-3: MTEP17 dynamic stability models

The MTEP16 dynamics data is the starting point for MTEP17 dynamics model development. This data is reviewed and updated with stakeholder feedback. Additionally, the ERAG MMWG 2016 series dynamic stability models are reviewed and any improved modeling data in external areas is incorporated in the MTEP17 dynamics models.

Dynamic load modeling is driven by Requirement 2.4.1 of the TPL-001-4 standard which started in MTEP16 dynamic models and continues into MTEP17 dynamics models. The dynamic load models must be represented by complex or composite load models to adequately capture the impact of induction motor loads. Assumptions for generator dispatch for stability models are the same as steady-state powerflow models.

The dynamics package is verified by running a 20-second, no-disturbance simulation and other sample disturbances at select generator locations in the MISO footprint. Test simulations are performed to enable a review of model performance. Charts showing simulation results are posted for stakeholder review.

During the MTEP17 dynamic models development process, stakeholders were asked to provide inputs on:

- Updates to existing dynamics data
- Additional dynamic models for new equipment
- Output quantities to be measured

Economic Study Models

Economic study models are developed for use in the MTEP economic planning studies. These models are forward-looking, hourly models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP17, the Planning Advisory Committee (PAC) approved the following future scenarios:[12]

- Existing Fleet
- Policy Regulations
- Accelerated Alternative Technologies

[12] For more details on these assumption scenarios, see Chapters 5.2: MTEP Future Development and 5.3: Market Congestion Planning Study.

The base data used in all future scenarios is maintained through the PROMOD PowerBase database. This database uses data provided annually by ABB as a starting point. MISO then goes through an annual, extensive model development process that updates the source data provided by ABB with MISO-specific updates.

Updates for MTEP17 include data obtained from the following sources:

- MISO Commercial Model for verifying generator maximum capacities and hub data
- Generator Interconnection Queues (MISO and neighbors) for future generators
- Module E data for energy and demand forecasts, behind-the-meter generation, interruptible loads and demand response data
- Powerflow model (developed through the MTEP process) for topology
- Publically announced generation retirements
- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff — see Chapter 5.2: MTEP Future Development)

As part of the economic model development process, the PowerBase database is verified to ensure data accuracy through numerous checks. Model verification is broadly comprised of generator economic data validation, demand and energy data checks and PowerBase-powerflow network topology mapping.

The PowerBase database, including system topology, was posted for stakeholder review in September 2016. During the review period stakeholders were asked to provide:

- Updates to generator data
    - Maximum and minimum capacity
    - Retirement dates
    - Emission rates
- Updates to powerflow model mapping to PowerBase
    - Generator bus mapping
    - Demand mapping
- Updates to contingencies and flowgates/interfaces monitored

In addition to the stakeholder review process, MISO collaborates with its tier one immediate neighbors as part of the model development process to accurately reflect neighboring systems. Highlights of this collaboration include extensive updates from PJM and Southwest Power Pool (SPP).

Book 1 / Transmission Studies

Section 3: Historical MTEP Plan Status

3.1 MTEP16 Active Project Status Report

MISO's transmission planning responsibilities include the monitoring of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners and Selected Developers on a quarterly basis to determine the progress of each project. Since 2006, these status updates are reported to the MISO Board of Directors and posted to the MISO MTEP Studies web page. This report provides the status of active MTEP Appendix A projects as of Quarter 3, 2017, and elaborates on the status of the Multi-Value Projects (MVP) approved in MTEP11.

MISO transmission planning responsibilities include monitoring progress and the implementation of previously approved MTEP Appendix A projects.

Active projects consist of previously approved Appendix A projects that are not withdrawn or in service. As of the third quarter of 2017, MISO is tracking 657 active projects totaling $10.7 billion of approved investment.. Of the total active investment, 22 percent were approved in MTEP16 and the remaining 78 percent were approved in MTEP03 through MTEP15. Since the first MTEP report in 2003, a total of $33 billion in transmission projects have been approved. Of this approved investment, $15.4 billion have been constructed; $4.2 billion has been withdrawn; and the remaining $13.4 billion is in various stages of design, planning or construction through the third quarter of 2017.

Following the approval of a MTEP, MISO continues to provide transparency through its publication of quarterly project status updates. This monitoring of previously approved MTEP Appendix A projects ensures that a good-faith effort is being made to move projects forward, as prescribed in the Transmission Owners' Agreement. Transmission Owners and Selected Developers provide updated costs, in-service dates and various other status updates as required by the MISO Tariff and BPM-020.

The status of these projects is shown in Figure 3.1-1 along with the total current investment for each MTEP cycle. The breakdown of those projects by facility type is provided in Figure 3.1-2.

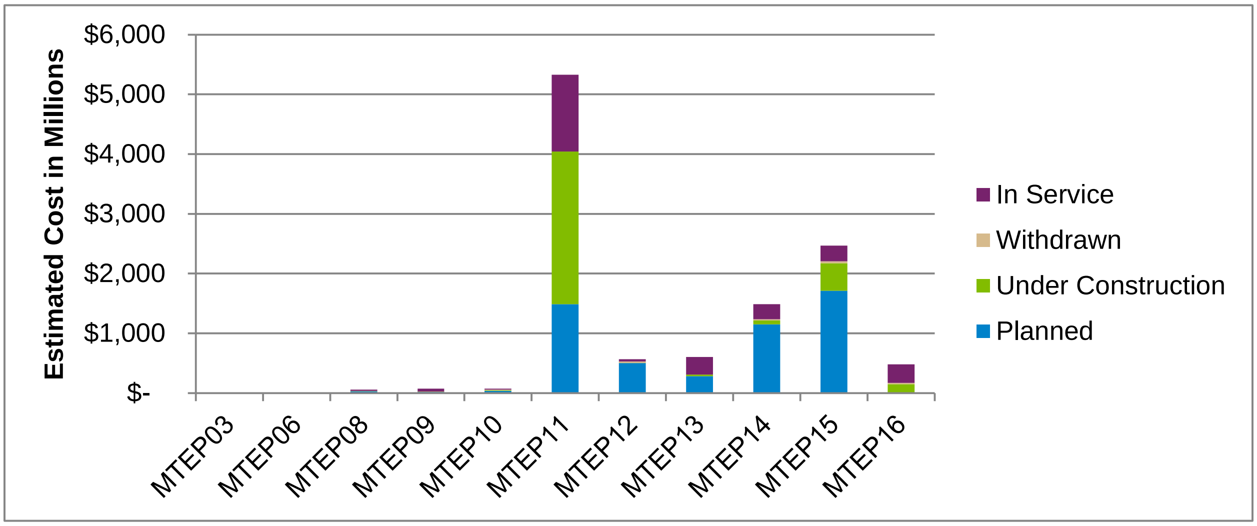


Figure 3.1-1: Project Status of Active Projects

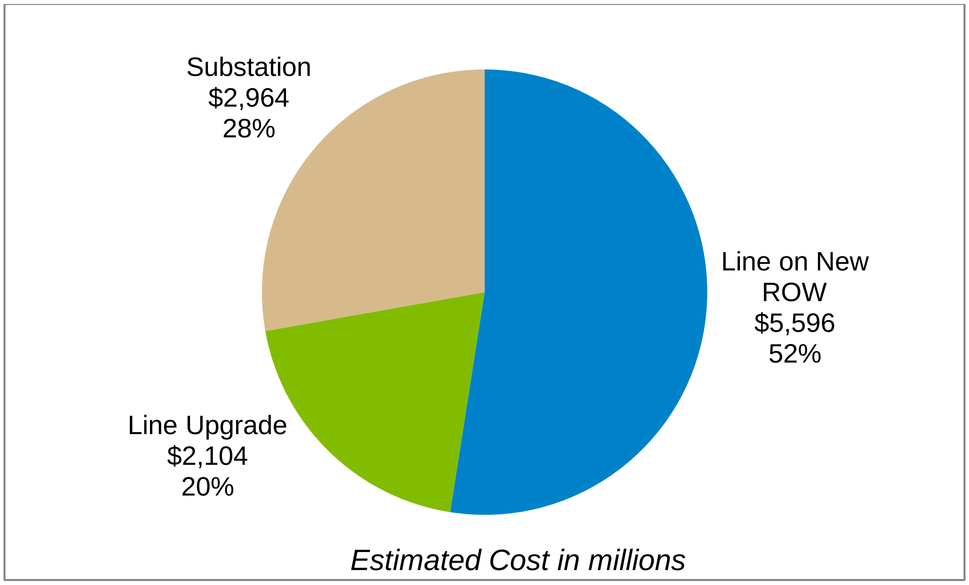


Figure 3.1-2: Facility Cost of Active Projects

Multi-Value Project Portfolio Status

The MVPs are part of a regionally planned portfolio of transmission projects. The MVP portfolio represents the culmination of more than eight years of planning efforts to find cost-effective regional transmission solutions while meeting local energy and reliability needs. The MVP portfolio is expected to[13]:

- Provide benefits in excess of its costs under all scenarios studied with benefit-to-cost ratios ranging from 1.8 to 3.0
- Resolve reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigate 31 system instability conditions
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals

The 17 MVPs are generally projected to meet budget and schedule expectations. As of October 2017, five projects are in service, nine projects are at least partially under construction and the remainder are complete or are in progress with state regulatory approvals (Figure 3.1-3).

The MVP dashboard (Figure 3.1-3) is updated quarterly and the most up to date version can be referenced from the MISO website.

[13] Source: Candidate MVP Report. A review of the MVP Portfolio's benefits is contained in Section 7.5.

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[2]			Explanation[6]
			MTEP Approved	August 2017	State Regulatory Status	Construction	MTEP Approved[3]	MTEP Approved Dollars Adjusted to Estimated ISD[4]	August 2017[5]	
1	Big Stone - Brookings	SD	2017	2017	●	Complete	$227	$263	$141	
2	Brookings, SD - SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	$738	$738*	$670	
3	Lakefield Jct - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster	MN/IA	2015-2016	2015-2018	●	Underway	$550	$654	$651	A - E
4	Winco - Lime Creek - Emery - Black Hawk-Hazleton	IA	2015	2015-2019	●	Underway	$469	$571	$564	B, C, D & E
5	N. LaCrosse - N. Madison - Cardinal (a/k/a Badger - Coulee Project)	WI	2018	2018	●	Underway	$798	$1,073	$1,016	A, F
	Cardinal - Hickory Creek	WI/IA	2020	2023	○	Pending				A, D, F
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Underway	$331	$403	$320	
7	Ottumwa - Zachary	IA/MO	2017-2020	2018-2019	◐	Pending	$152	$186	$226	A,B,C,D
8	Zachary - Maywood	MO	2016-2018	2016-2019	◐	Pending	$113	$137	$172	A, D, E
9	Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin	MO/IL	2016-2017	2016-2017	●	Underway	$432	$501	$723	A, B
10	Austin - Pana	IL	2018	2016-2017	●	Underway	$99	$115	$135	A,B
11	Pana - Faraday - Kansas - Sugar Creek	IL/IN	2018-2019	2015-2019	●	Underway	$318	$388	$423	A,B
12	Reynolds - Burr Oak - Hiple	IN	2019	2018	●	Underway	$271	$322	$388	B,C
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	$510	$563	$504	
14	Reynolds - Greentown	IN	2018	2013-2018	●	Underway	$245	$299	$388	B
15	Pleasant Prairie - Zion Energy Center	WI	2014	2013	●	Complete	$29	$30	$36	E, F
16	Fargo- Sandburg - Oak Grove	IL	2014-2019	2016-2018	●	Pending	$199	$237	$204	
17	Sidney - Rising	IL	2016	2016	●	Complete	$83	$94	$88	
						Total	**$5,564**	**$6,573**	**$6,651**	

Footnotes:

[1] Estimated ISD provided by constructing Transmission Owners.
[2] Costs stated in millions.
[3] MTEP11 approved cost estimates provided by constructing Transmission Owners.
[4] MTEP11 approved cost estimates escalated to the estimated in-service year dollars based on MISO's 2.50% annual inflation rate.
[5] Current cost estimates provided by constructing Transmission Owners. This represents the estimated cost for ratebase purposes.
[6] Explanation for cost variance beyond annual inflation escalation. See below for explanation.
* MTEP11 approved cost estimate was provided in nominal (expected year of spend) dollars.

State Regulatory Status Indicator Scale	
○	Pending
◐	In regulatory process or partially complete
●	Regulatory process complete or no regulatory process Requirements

Explanations	**Examples:** Detailed information can be found in the MTEP Quarterly Status Update
A. Regulatory Requirements	Routing changes, timing delays, structure changes, and equipment modifications necessary to fulfill regulatory requirements.
B. Engineering & Design Standards	Modifications to foundations, structures, lines, and substations resulting from detail design, route selection and/or new NERC standards.
C. Material / Commodity Pricing	Price escalation variances above and beyond standard escalation assumption (including labor).
D. Schedule Delay	Increased cost due to changes in scheduling and, if applicable, the resulting higher AFUDC.
E. Costs associated with delayed ISD	Route changes due to legal or right-of-way issues, changes in material availability or costs, and new standards.
F. Other	Described in the MTEP Quarterly Status Update.

Figure 3.1-3: MVP Planning and Status Dashboard as of October 2017

3.2 MTEP Implementation History

The annual MTEP report is the culmination of more than 18 months of collaboration between MISO and its stakeholders. Each report cycle focuses on identifying issues and opportunities, developing alternatives for consideration and evaluating those options to determine effective transmission solutions. With the MTEP17 cycle, the MTEP report now represents 14 years of planning these essential upgrades and expansions to the electric transmission grid.

The number of projects and investment can vary dramatically from year to year depending on a variety of system needs. Project drivers could include changes in generation mix due to economics or environmental emissions control, the need to mitigate system congestion at load delivery points, or the addition of large industrial loads. These projects improve the deliverability of energy both economically and reliably to consumers in the MISO footprint and beyond.

After projects are approved by the MISO Board of Directors, these projects will go through any required approval processes by federal or state regulatory authorities and subsequent construction. The system needs originally driving these projects may change or disappear. When these material system changes transpire, MISO collaborates with transmission owners and stakeholders to withdraw or partially withdraw an approved project such that system reliability is always maintained.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP17 cycle, is more than $33 billion (Figure 3.2-1). MTEP17 data depicted in this figure, subject to board approval, will be added to the data tracked for the MISO Board of Directors. These statistics only include projects for MISO members who participated in this planning cycle. Previously approved projects for prior MISO members are not included in these statistics.

- $3.4 billion of MTEP projects are expected to go into service in 2017

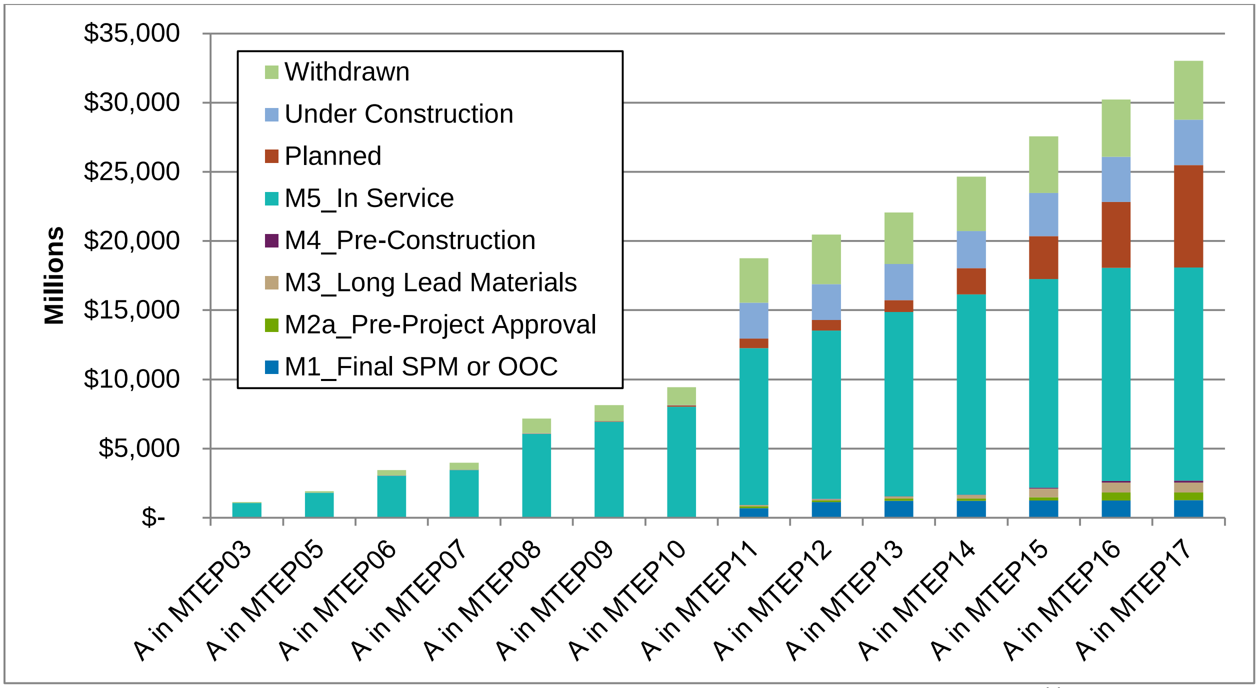


Figure 3.2-1: Cumulative transmission investment by facility status[14]

The historical perspective of MTEP project investment for each MTEP cycle shows extensive variability in development (Figure 3.2-2). This is caused by the long development time of transmission plans and the regular, periodic updating of the transmission plans. Approval of the Multi-Value Projects (MVP) portfolio explains the large increase between MTEP10 and MTEP11.

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small incremental value of projects in MTEP07.
- MTEP08 shows the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analyses and determination of the best plans to serve those needs. The in-service category increases as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts.
- MTEP11 contains the MVP portfolio, which accounts for the significantly higher investment totals compared to other MTEPs. MVP status and investment totals are tracked via the MVP Dashboard.
- MTEP12 and MTEP13 reflect a return to a more typical MTEP, primarily driven by reliability projects.
- MTEP14 reflects a continuation of a typical MTEP, primarily driven by reliability projects, but with the inclusion of the new MISO South region projects. A single transmission delivery service project accounts for around 25 percent of the total MTEP14 investment.
- MTEP15 and MTEP16 further reflect a continuation of a typical MTEP, primarily driven by reliability projects. Beginning in MTEP15, MTEP participants began planning to meet a series of new, more stringent NERC reliability standards.

[14] Project milestones described in Chapter 3.1: Prior MTEP Plan Status

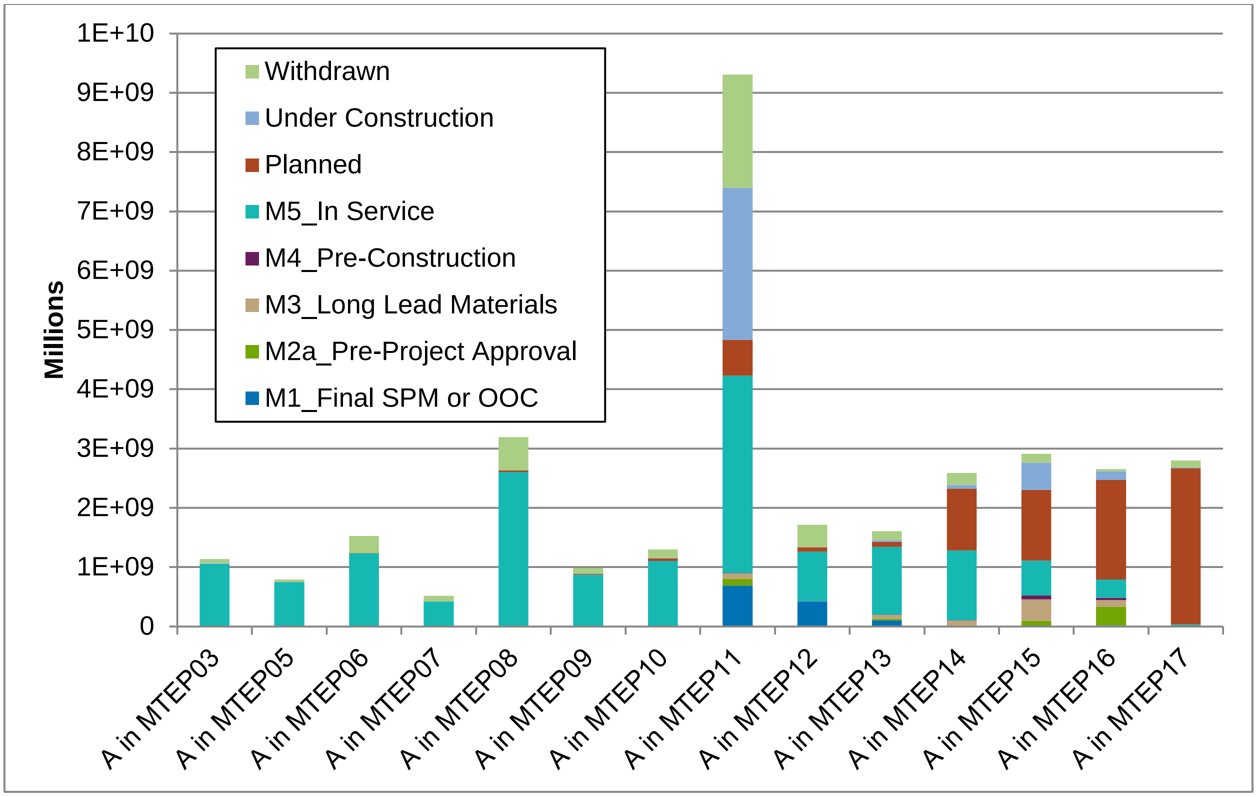


Figure 3.2-2: Approved transmission investment by MTEP cycle[15]

Since MTEP03, approximately $4.2 billion in approved transmission investment has been withdrawn. Common reasons for a project withdrawal include:

- The customer's plans changed or the service request was withdrawn
- A material system change resulted in no further need for the project
- An alternative solution is pursued and/or further evaluation shows the project is not needed

MISO documents all withdrawn projects and facilities to ensure the planning process addresses required system needs.

[15] New Appendix A projects in the MTEP17 column contain a few in-service and under-construction projects. There are a few reasons why this occurs. Generator Interconnection Projects with network upgrades are approved via a separate Tariff process and are brought into the current MTEP cycle after their approval. There are also projects driven by conditions that must be addressed promptly to maintain system reliability. There are clearance projects that should be addressed promptly to maintain system reliability. Finally, there are relocation projects driven by others' schedules.

Book 1 / Transmission Studies

Section 4: Reliability Analysis

4.1 Reliability Assessment and Compliance

System reliability is the primary purpose of all MTEP planning cycles. To fulfill this purpose, MISO planners study reliability from multiple perspectives to confirm the transmission system has sufficient capacity to provide reliable service to customers.

Continued reliability of the transmission system is measured by compliance with regional and local Transmission Owner (TO) planning criteria. These standards define minimum requirements for long-term system planning and require explicit solutions for violations that occur in a two-, five- and 10-year timeframe. As planning coordinator, MISO is required to find a solution for each identified violation that could otherwise lead to overloads, loss of synchronism, voltage collapse, equipment failures or blackouts.

The results of these reliability analyses, along with the proposed mitigating transmission projects, were presented and peer-reviewed at a series of Subregional Planning Meetings that were held in December 2016, May-June 2017 and August 2017. Each project included in MTEP Appendix A is the preferred solution to a transmission need when its implementation timeline requires near-term progress towards regulatory approval and construction.

The details of the MTEP17 reliability assessment are summarized in this chapter and the complete results are presented in Appendix D of this MTEP17 report.

Process Overview

The MTEP reliability assessment is a holistic study process that begins with MISO building a series of study cases. Using these models, MISO staff performs an independent reliability analysis of its transmission system. This independent assessment results in identification of system needs, which are mapped to project submittals by the area transmission planning entities. Finally, MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required (Figure 4.1-1).

MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required.

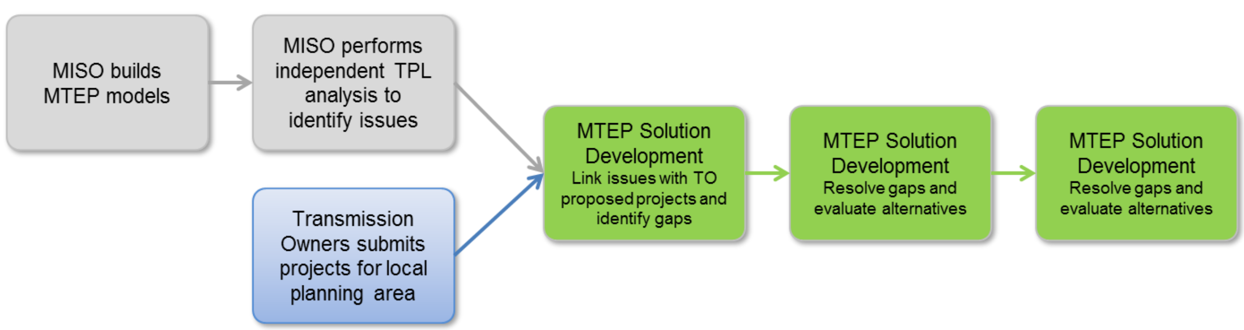


Figure 4.1-1: MTEP17 Reliability Study Process

Models

In MTEP17, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with its stakeholders:

- 2019 Summer Peak (wind at 15 percent)
- 2019 Light Load (wind at 0 percent)
- 2022 Summer Peak (wind at 15 percent)
- 2022 Shoulder Peak (wind at 40 percent)
- 2022 Shoulder Peak (wind at 90 percent)
- 2022 Shoulder Peak (wind at 90 percent)
- 2022 Winter Peak (wind at 40 percent)
- 2027 Summer Peak (wind at 15 percent)

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance.

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP17 reliability analysis.

MISO member companies and external Regional Transmission Organizations use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2016 series Multiregional Modeling Working Group (MMWG) interchange.[16] MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

Generation dispatch within the model-building process is complex. Inputs from a variety of processes and expected shifts in the generation portfolio within the MISO footprint are key factors in this complexity.

Inputs in the dispatching process include:

- Generation retirements
- Generator market cost curves
- Generator deliverable capacity designation
- Wind generation output modeling under various system conditions
- Incremental generation needed to meet applicable renewable mandates

Loads are modeled based on direct input from MISO members. Generation dispatch is based on a number of assumptions, such as the modeling of wind. For example, wind generation is dispatched at 14 to 15.6 percent of nameplate in the summer peak case and from 40 to 90 percent of nameplate in the shoulder cases. These wind dispatch levels were selected through the MISO planning stakeholder process. More information on the models may be found in Appendix D2 of this report.

NERC Reliability Assessment

MISO conducts baseline reliability studies to ensure its transmission system is in compliance with three sets of standards:

- Applicable North American Electric Reliability Corp. (NERC) reliability standards
- Reliability standards adopted by Regional Entities (RE) applicable within the transmission provider region
- Local Transmission Owner (TO) planning criteria after it is filed and approved by Federal Energy Regulatory Commission (FERC)

Based on the NERC reliability assessment performed by MISO, potential thermal and voltage reliability issues are identified. MISO and its TOs are required to develop and implement solutions for each

[16] https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/Pages/default.aspx

identified constraint. Violations are mitigated via system reconfiguration, generation redispatch, implementation of an operating guide, or with a transmission upgrade, as appropriate and consistent with the requirements of the applicable reliability standards. Identified transmission upgrades to future system issues are investigated further in subsequent MTEP cycles.

MISO is in discussions at the Planning Subcommittee meetings on how to better incorporate non-transmission alternatives in the reliability planning process. A business practice manual is under development.

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance. The complete study is available in Appendices D2-D8 of this report, which is posted on the MISO SFTP site. Confidential appendices, such as D2 through D8, are available on the MISO MTEP17 Planning Portal. Access to the Planning Portal site requires an ID and password.

Each MTEP assessment undergoes three specific types of analysis: steady-state, dynamic stability and voltage stability.

Steady-State Analysis

Appendix E1.5.1 documents contingencies tested in steady-state analysis. These contingencies were used in the MTEP17 2019 summer peak and shoulder peak models; the 2022 summer peak, shoulder peak, winter peak and light-load models; and the 2027 summer peak model. All steady-state analysis-identified constraints and associated mitigations are contained in the results tables in Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Dynamic Stability Analysis

Appendix E1.5.2 documents types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP17 2022 light load, shoulder (wind at 40 percent), shoulder (wind at 90 percent) and summer peak load models. Results tables listing all simulated disturbances along with damping ratios are tabulated in Appendix D5, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis

Appendix E1.5.3 documents types of transfers tested in voltage stability analysis. A summary report with associated PV plots is documented in Appendix D4.

Subregional Planning Meetings

MISO presents the project proposals and reliability study results to stakeholders through a series of public Subregional Planning Meetings (SPM). The locations of these SPMs are determined based on the four MISO planning subregions (Figure 4.1-2). The four MISO planning subregions are: Central, East, South and West.

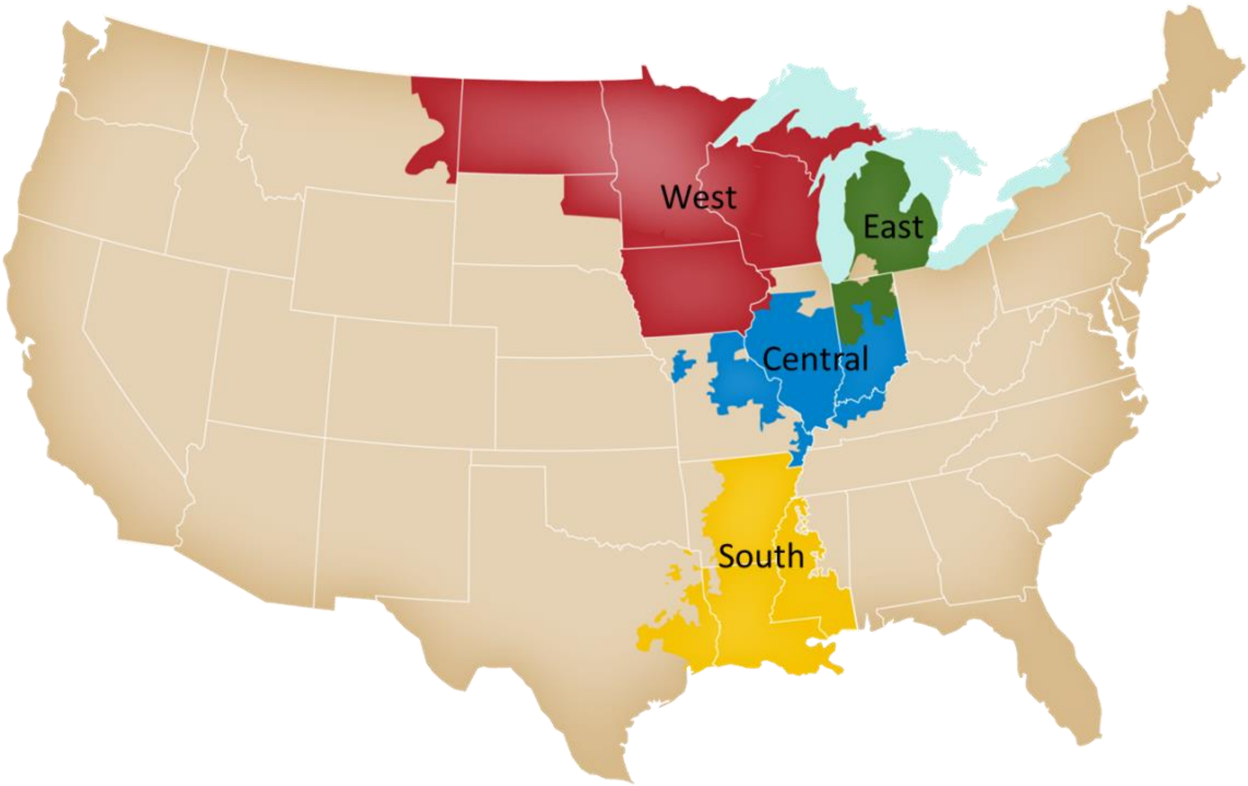


Figure 4.1-2: MISO planning subregions

Additionally, Technical Study Task Force (TSTF) meetings are convened for each MISO planning subregion on an as-needed basis to discuss confidential system information (Table 4.1-1). These meetings are open to any stakeholders who sign Critical Energy Infrastructure Information (CEII) and non-disclosure agreements.

Date	Meeting	Location
12/01/16	Central SPM No. 1	Carmel, Ind.
12/06/16	East SPM No. 1	Livonia, Mich.
12/07/16	West SPM No. 1	Eagan, Minn.
12/08/16	South SPM No. 1	Metairie, La.
05/24/17	Central SPM No. 2	Carmel, Ind.
05/24/17	South SPM No. 2	Metairie, La.
05/31/17	East SPM No. 2	Livonia, Mich.
06/01/17	West SPM No. 2	Eagan, Minn.
08/25/17	Central SPM No. 3	Carmel, Ind.
08/31/17	West SPM No. 3	Eagan, Minn.
08/30/17	East SPM No. 3	Cadillac, Mich.
08/22/17	South SPM No. 3	Metairie, La.

Table 4.1-1: MTEP17 Subregional Planning Meeting schedule

Project Approval

After MISO completes the independent review of all proposed projects and addresses any stakeholder feedback received during the SPM presentations, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP17 report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessment. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles. Details of the project approval process and the approved transmission projects reviewed this cycle are summarized in Chapter 2 and Appendix D1 of the MTEP17 report.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, transparent, equal and non-discriminatory access to the electric transmission system for all new generation interconnection requests. MISO's interconnection process identifies network upgrades for all new generator interconnection requests, as necessary, to ensure that the injection from new generation capacity does not deteriorate the reliability of the existing transmission system. All network upgrades emanating from the interconnection process are included in the final MTEP as Generator Interconnection Projects (GIPs) at the end of every calendar year.

MTEP17 contains Target Appendix A GIPs totaling approximately $237.6 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests (Table 4.2-2, Figure 4.2-1).

MTEP Project ID	Project Name	Submitting Company	Preliminary Share Status	Region	Estimated Cost ($)
12643	J485 Network Upgrades	RPU	Not Shared	West	$1,796,900
12283	J384 Network Upgrades	ATC	Shared	ATC	$159,000
12284	J395 Falcon Substation and Network Upgrades	ATC	Shared	ATC	$18,600,000
13103	J390 Kittyhawk Substation	ATC	Shared	ATC	$49,500,000
12056	J396 Almonaster to Midtown 230 kV: Reconductor Line	EES-LA	Not Shared	South	$5,916,000
12142	J396 Snakefarm to Labarre 230 kV: Upgrade station equipment	EES-LA	Not Shared	South	$20,000
12774	J396 St. Charles Power Station Interconnection	EES-LA	Not Shared	South	$25,504,000
12167	J416 Generator Interconnection	ITCM	Shared	West	$26,230,018
12168	J278 Hazleton-Mitchell 345 kV uprate	ITCM	Shared	West	$3,360,000
12665	J498 Beaver Creek	ITCM, MEC	Shared	West	$10,000,000
12263	J316 Network Upgrades	MDU	Not Shared	West	$2,865,000
12723	J499 Arbor Hill	MEC	Shared	West	$10,000,000
12725	J500 Orient	MEC	Shared	West	$24,571,000
12923	G736 Crown Ridge Wind Farm	OTP	Not Shared	West	$0
11644	G261 Mankato Energy Center Expansion (XEL portion)	XEL	Not Shared	West	$500,000
11645	H081 – Hawk's Nest Lake Substation	XEL	Shared	West	$10,875,000
12623	J426 Chanarambie Expansion	XEL	Not Shared	West	$5,250,000
13344	R101 Red Lake Falls Wind/Solar	OTP	Not Shared	West	$72,630
13444	G934 Nelson Road Interconnection	METC	Shared	Central	$4,281,000
13384	J589 Luce 138 kV substation	METC	Not Shared	Central	$8,115,000
13584	J529/J590 Palo Alto	MEC	Shared	West	$10,000,000
13644	J412 Generator Interconnection	ITCM	Shared	West	$10,000,000
13645	J455 Ypland Prairie	MEC	Shared	Wes	$10,000,000
Total Estimated Cost					**$237,615,548**

Table 4.2-1 Generation Interconnection Projects in MTEP17 Target Appendix A[17]

[17] A detailed description how a shared project is determined is in Attachment FF, starting with Section II.C, page 57 of 499 of the Tariff.

GI Project No.	TO	County	ST	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
J485	RPU	Olmsted	MN	DPP-2016-FEB	NRIS	West Side 161 kV substation	46.85	Gas	GIA
J384	ATC	Dane	WI	DPP-2015-FEB	NRIS	Christiana 138 kV substation	21	Gas	GIA
J395	ATC	Lafayette	WI	DPP-2015-FEB	ERIS	Hillman – Darlington 138 kV line	98	Wind	GIA
J390	ATC	Rock County	WI	DPP-2015-Feb	NRIS	Paddock – Rockdale 345 kV line	702	CCT	GIA
J396	EES-LA	St. Charles	LA	DPP-2015-AUG	NRIS	Little Gypsy 230 kV Power Station	923.8	CCT	GIA
J416	ITCM	Franklin	IA	DPP-2015-FEB	NRIS	Emery – Blackhawk 345 kV line	200	Wind	GIA
J278	GRE	Mower	MN	DPP-2013-AUG	ERIS	Pleasant Valley 161 kV substation	200	Wind	GIA
J498	MEC	Boone and Greene	IA	DPP-2016-FEB	NRIS	Grimes – Lehigh 345 kV line	340	Wind	GIA
J316	MDU	Dickey	ND	DPP-2014-AUG	NRIS	Tatanka – Ellendale 230 kV line	150	Wind	GIA
J499	MEC	Adair and Madison	IA	DPP-2016-FEB	NRIS	Fallow – Grimes 345 kV line	340	Wind	GIA
J500	MEC	Adair	IA	DPP-2016-FEB	NRIS	Boone – Atchison and Rolling Hills – Madison 345 kV line	500	Wind	GIA
G736	OTP	Grant	SD	DPP-2015-FEB	NRIS	Big Stone South 230 kV substation	200	Wind	GIA
G261	XEL	Blue Earth	MN	DPP-2012-AUG	NRIS	Wilmarth 345 kV substation	667	CCT	GIA
H081	XEL	Lyon	MN	DPP-2012-AUG	ERIS	Brookings County – Lyon County 345 kV line	200	Wind	GIA
J426	XEL	Pipestone	MN	DPP-2015-FEB	NRIS	Chanarambie 35.4 kV substation	100	Wind	GIA
R101	OTP	Red Lake	MN	Fast Track	NRIS	Red Lake Falls SW – Gentilly 41.6 kV line	4.6	Wind/ Solar	GIA
G934	METC	Gratiot	MI	DPP-2015-AUG-MI	NRIS	Nelson Road 345 kV substation	150	Wind	GIA
J455	MEC	Clay	IA	DPP-2015-AUG-West	ERIS	Kossuth – Obrien 345 kV line	300	Wind	*
J589	METC	Gratiot	MI	DPP-2016-AUG-MI	NRIS	Regal – Summerton 138 kV line	148.8	Wind	*
J529/J590	MEC	Palo Alto	IA	DPP-2016-FEB-West	NRIS	Obrien - Kossuth 345 kV line	250	Wind	GIA
J412	ITCM	Ida	IA	DPP-2015-AUG-West	NRIS	LeHigh – Raun 345 kV line	200	Wind	*

Table 4.2-2: Generation Interconnection Requests associated with Target Appendix A

*GIA In Process

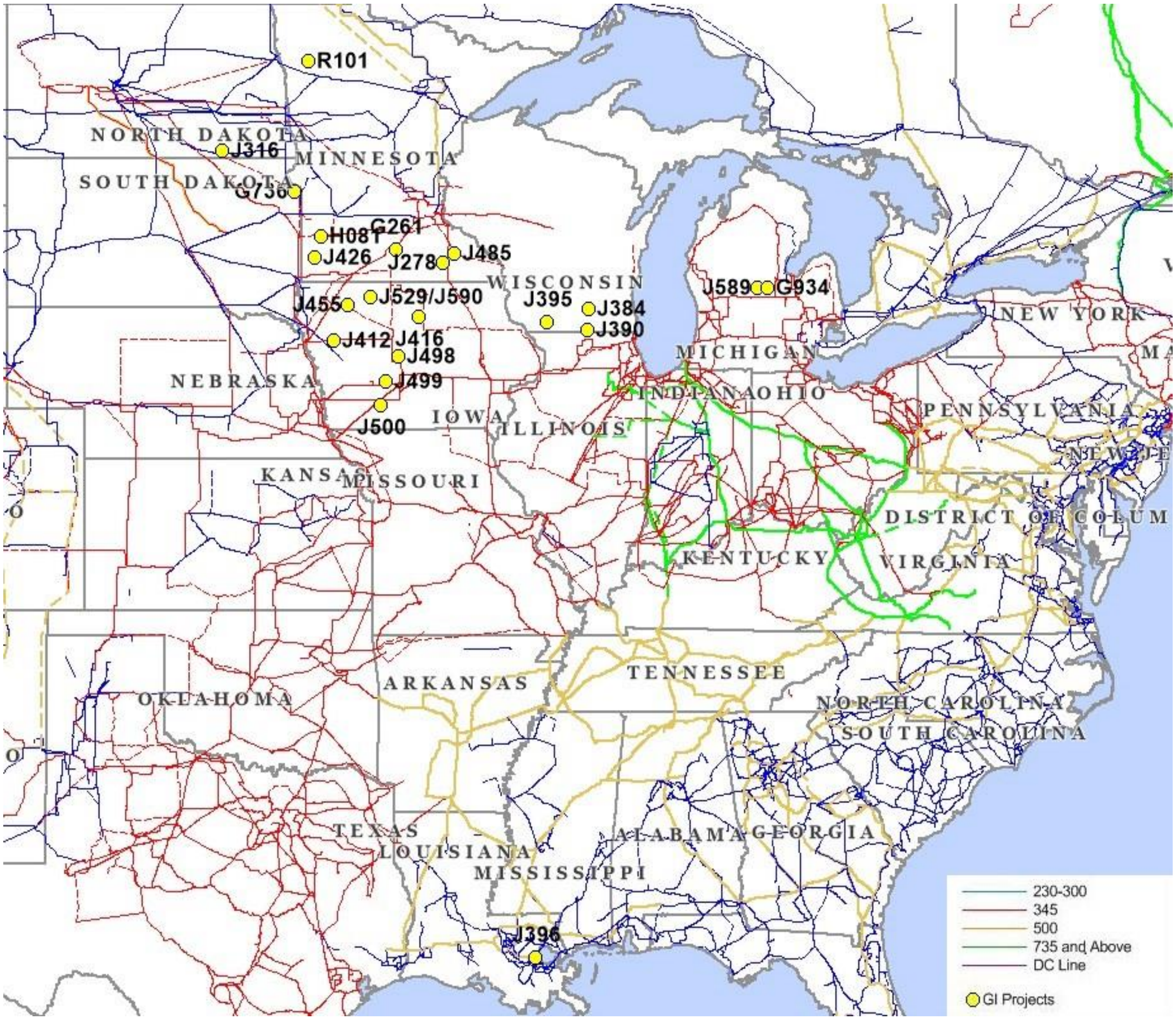


Figure 4.2-1: Generation Interconnection Requests associated with MTEP17 Target Appendix A

MTEP17 Target Appendix A

Generation Interconnection Projects – Detail

MTEP Project 12643 – Rochester Public Utilities Co.

- Perform network upgrades for J485 GIP
- J485 – 46.85 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: West Side 161 kV substation
- Upgrade the West Side 161 kV Sub Reconfiguring to a Ring Bus
- Add three 161 kV breakers
- Completion date: September 15, 2017
- Actual cost: $1,796,900

MTEP Project 12283 – American Transmission Co.

- Perform network upgrades for J384 GIP
- J384 – 21 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Christiana 138 kV substation
- Upgrade Cooney – Summit 138 kV line
- Anticipated completion date: December 1, 2017
- Anticipated cost: $159,000

MTEP Project 12284 – American Transmission Co.

- Perform network upgrades for J395 GIP
- J395 – 98 MW Wind Generation
- Point of interconnection: Hillman – Darlington 138 kV line
- Upgrade the Falcon 138 kV substation
- Upgrade the Darlington – North Monroe (x-49) 138 kV line
- Anticipated completion date: December 1, 2017
- Anticipated cost: $18,600,000

MTEP Project 13103 – American Transmission Co.

- Perform network upgrades for J390 GIP
- J390 – 702 MW Combined Cycle Turbine Generator
- Point of interconnection: Paddock – Rockdale 345 kV line
- Construct the Kittyhawk 345 kV substation
- Construct the 345 kV line to interconnect to the Kittyhawk 345 kV substation
- Anticipated completion date: April 30, 2019
- Anticipated cost: $49,500,000

MTEP Project 12056 – Entergy - Louisiana

- Perform network upgrades for J396 GIP
- J396 – 923.8 MW Combined Cycle Turbine Generator
- Point of interconnection: Little Gypsy 230 kV Power Station
- Upgrade Almonaster – Midtown 230 kV line to a Minimum of 1,600 Amps
- Anticipated completion date: December 30, 2017
- Anticipated cost: $5,916,000

MTEP Project 12142 – Entergy - Louisiana

- Perform network upgrades for J396 GIP
- J396 – 923.8 MW Combined Cycle Turbine Generator
- Point of interconnection: Little Gypsy 230 kV Power Station
- Upgrade Station Line Bay Bus to a minimum of 1,608 Amps to match the conductor rating
- Anticipated completion date: June 1, 2018
- Anticipated cost: $20,000

MTEP Project 12774 – Entergy - Louisiana

- Perform network upgrades for J396 GIP
- J396 – 923.8 MW Combined Cycle Turbine Generator
- Point of interconnection: Little Gypsy 230 kV power station
- Generation interconnection projects needed for St. Charles Power Station
- Anticipated completion date: June 1, 2018
- Anticipated cost: $25,504,000

MTEP Project 12167 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J416
- J416 – 200 MW Wind Generator.
- Point of interconnection: Emery – Blackhawk 345 kV line
- Construct new Quinn 345 kV switching station
- Construct approximately 9.5 miles of 345 kV gen-tie line as Transmission Owner Interconnection Facility
- Anticipated completion date: October 1, 2018
- Anticipated cost: $26,230,018

MTEP Project 12168 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J278
- J278 – 200 MW Wind Generator.
- Point of interconnection: Pleasant Valley 161 kV substation
- Raise structures on the Mitchell - Hazelton 345 kV line to achieve 995 MVA summer rating
- Anticipated completion date: December 31, 2020
- Anticipated cost: $3,360,000

MTEP Project 12665 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J498
- J498 - 340 MW Wind Generator
- Point of interconnection: Grimes – Lehigh 345 kV line
- Construct new three-breaker 345 kV ring bus substation off the Lehigh - Grimes 345 kV line with two line taps and transposition structures
- Completion date: September 4, 2017
- Actual cost: $10,000,000

MTEP Project 12263 – Minnesota – Dakota Utility Co.

- Perform network upgrades for J316 GIP
- J316 – 150 MW Wind Generator
- Point of interconnection: Tatanka – Ellendale 230 kV line
- Reconductor Ellendale - Foxtail 230 kV line
- Anticipated completion date: December 15, 2017
- Anticipated cost: $2,865,000

MTEP Project 12723 – MidAmerican Energy Co.

- Perform network upgrades for J499 GIP
- J499 - 340 MW Wind Generator
- Point of interconnection: Fallow – Grimes 345 kV line
- Complete network upgrades and affected system upgrades
- Anticipated completion date: September 1, 2018
- Anticipated cost: $10,000,000

MTEP Project 12725 – MidAmerican Energy Co.

- Perform network upgrades for J500 GIP
- J500 – 500 MW Wind Generator
- Point of interconnection: Boone – Atchison and Rolling Hills – Madison 345 kV line
- Complete network upgrades and affected system upgrades
- Anticipated completion date: April 1, 2019
- Anticipated cost: $24,571,000

MTEP Project 12923 – Otter Tail Power Co.

- Perform network upgrades for G736 GIP
- G736 – 200 MW Wind Generator
- Point of interconnection: Big Stone South 230 kV substation
- Complete upgrades needed to interconnect a 200 MW wind generating facility to the Big Stone South 230 kV substation
- Anticipated completion date: December 31, 2018
- Anticipated cost: $0

MTEP Project 11644 – Xcel Energy Co.

- Perform network upgrades for G261 GIP
- G261 – 667 MW Combined Cycle Turbine Generator
- Point of interconnection: Wilmarth 345 kV substation
- To achieve the 150.7 MVA line rating for both summer normal and emergency conditions, Xcel Energy will mitigate clearance issues on this line
- Anticipated completion date: October 1, 2018
- Anticipated cost: $500,000

MTEP Project 11645 – Xcel Energy Co.

- Perform network upgrades for H081 GIP
- H081 – 200 MW Wind Generator
- Point of interconnection: Brookings County – Lyon County 345 kV line
- Construct a new 345 kV substation for the wind farm to connect its 345 kV line
- Completion date: September 1, 2017
- Actual cost: $10,875,000

MTEP Project 12623 – Xcel Energy Co.

- Perform network upgrades for J426 GIP
- J426 – 100 MW Wind Generator
- Point of interconnection: Chanarambie 35.4 kV substation
- Expand Chanarambie substation to accommodate TR3, bus tie breaker, and 34.5 kV feeders
- Anticipated completion date: December 15, 2018
- Anticipated cost: $5,250,000

MTEP Project 13344 – Otter Tail Power Co.

- Perform network upgrades for R101 GIP
- R101 – 4.6 MW Wind/Solar Generator
- Point of interconnection: Red Lake Falls SW – Gentilly 41.6 kV line
- Upgrade GOVB switch, laminate wood structure, grading structure, communication equipment, and relaying protection at Crookston 115/41.6 kV substation
- Anticipated completion date: January 27, 2018
- Anticipated cost: $72,630

MTEP Project 13384 – Michigan Electric Transmission Co.

- Perform network upgrades for J589 GIP
- J589 – 148.8 MW Wind Generator
- Point of interconnection: Regal – Summerton 138 kV line
- Construct a new Luce 138 kV substation
- Upgrades needed to connect MISO generator J589 to the METC 138 kV system
- Anticipated completion date: October 26, 2018
- Anticipated cost: $8,115,000

MTEP Project 13444 – Michigan Electric Transmission Co.

- Perform network upgrades for G934 GIP
- G934 – 150 MW Wind Generator
- Point of interconnection: Nelson Road 345 kV substation
- Install four 345 kV breakers and disconnect switches at the Nelson 345 kV substation
- Anticipated completion date: September 1, 20120
- Anticipated cost: $4,281000

MTEP Project 13584 – MidAmerican Energy Co.

- Perform network upgrades for J529/J590 GIP
- J529/J590 – 340 MW Wind Generator
- Point of interconnection: Obrien – Kossuth 345 kV line tap
- Install new three-breaker 345 kV ring bus substation off the Obrien-Kossuth 345 kV line with two taps
- Anticipated completion date: September 15, 2018
- Anticipated cost: $10,000,000

MTEP Project 13644 – Michigan Electric Transmission Co.

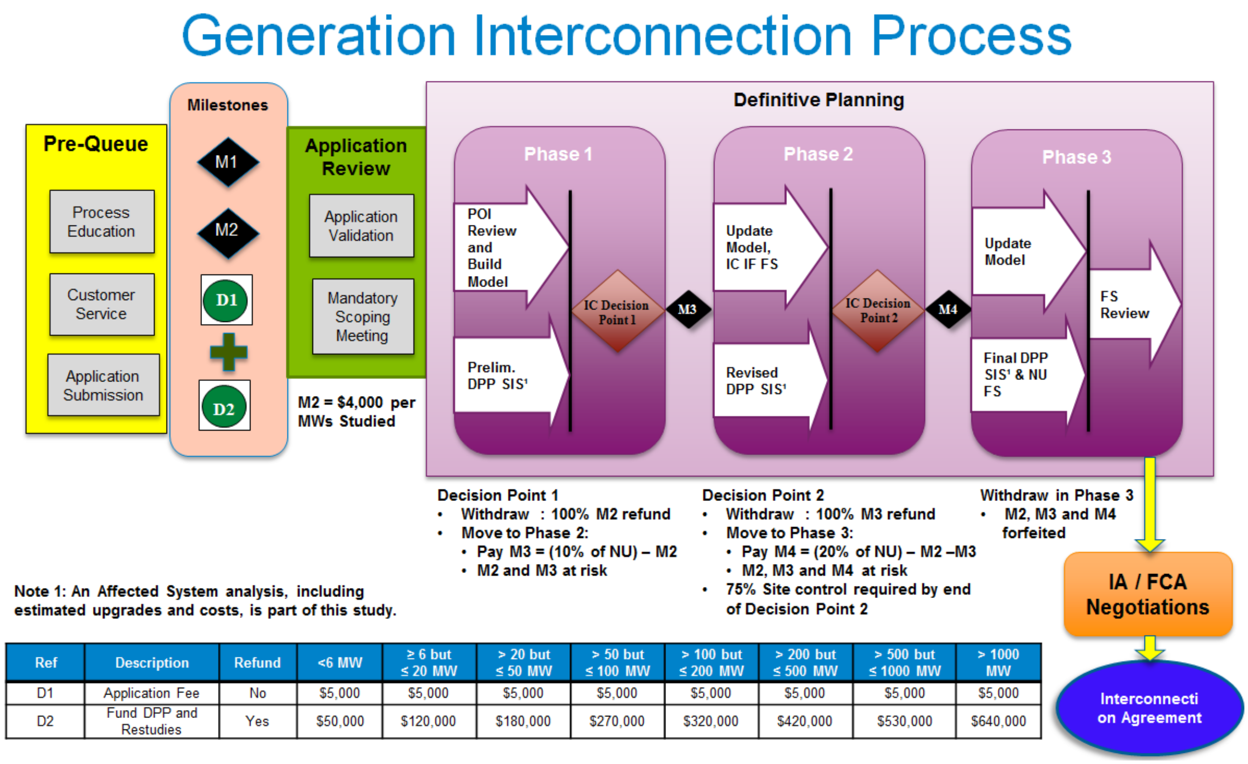
- Perform network upgrades for J412 GIP
- J412 – 200 MW Wind Generator
- Point of interconnection: LeHigh - Raun345 kV line
- Install new three-breaker 345 kV ring bus substation off the Raun – Ida 345 kV line with two taps
- Anticipated completion date: October 1, 2019
- Anticipated cost: $10,000,000

MTEP Project 13645 – MidAmerican Energy Co.

- Perform network upgrades for J455 GIP
- J455 – 300 MW Wind Generator
- Point of interconnection: Kossuth – Obrien 345 kV line
- Install new three-breaker 345 kV ring bus substation off the Obrien-Kossuth 345 kV line with two taps
- Anticipated completion date: September 15, 201
- Anticipated cost: $10,000,000

The Queue Process

Requests to connect new generation to the system are studied and approved under the generation interconnection queue process. Each generator must fund the necessary studies to ensure new interconnections will not cause system reliability issues. Each project must meet technical and non-technical milestones in order to move to the next phase (Figure 4.2-2).



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but ≤ 1000 MW	> 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 4.2-2: Generator Interconnection Process

Since the beginning of the queue process, MISO and its Transmission Owners have received approximately 1,965 generator interconnection requests totaling 379.1 GW (Figures 4.2-3, 4.2-4 and 4.2-5). Among them, 60.4 GW out of the 379.1 GW or 16 percent are now connected to the transmission system. These generation additions enhance reliability, ensure resource adequacy, provide a competitive market to deliver benefit to ratepayers and help the industry meet renewable portfolio standards.

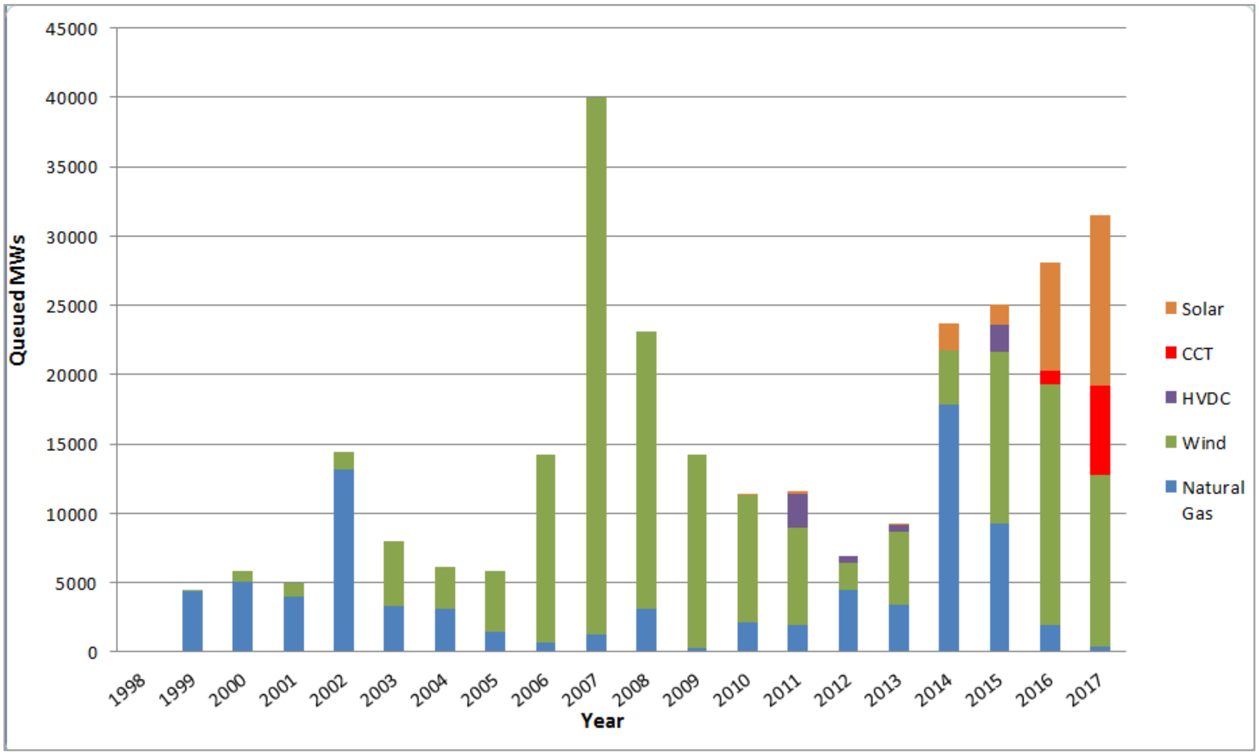
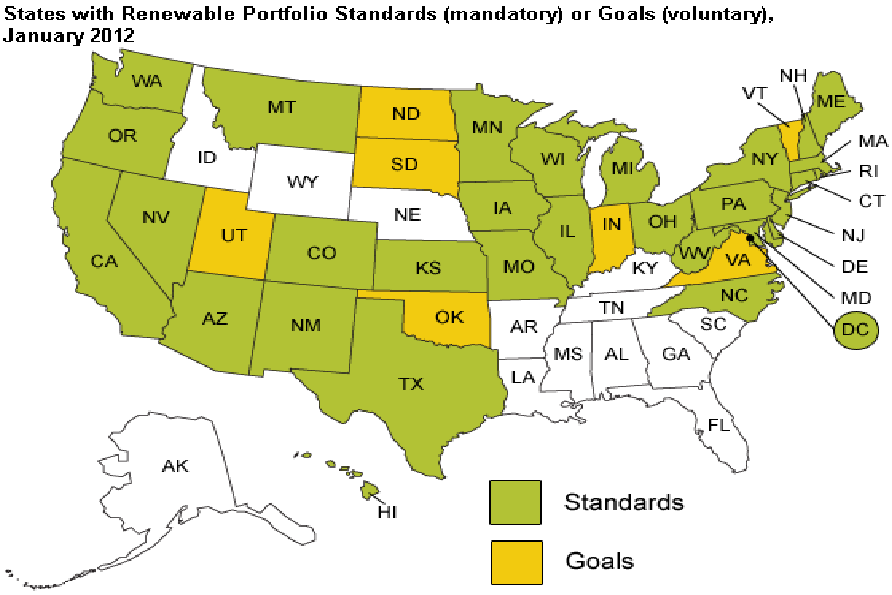


Figure 4.2-3: Queue Trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. Although there is no RPS program in place at the national level, 29 states and the District of Columbia had enforceable RPS or other mandated renewable capacity policies. In addition, eight states adopted voluntary renewable energy standards. Between 2005 and 2008, MISO experienced exponential growth in wind project requests. In 2007, wind generation requests in the MISO queue peaked at approximately 39 GW. These requests reflect the dramatic increase in registered wind capacity in the MISO footprint (Figure 4.2-4).



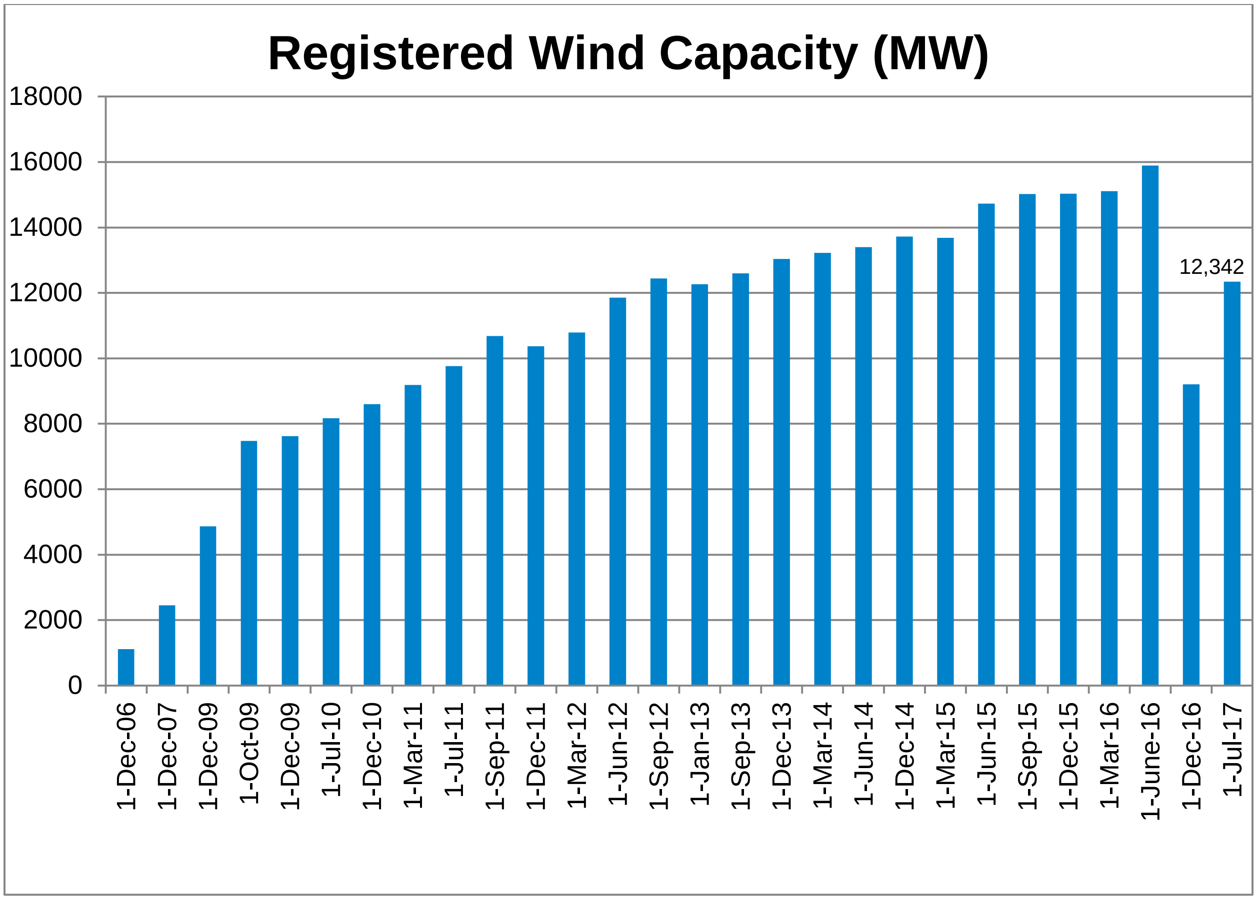


Figure 4.2-4: Nameplate wind capacity registered for MISO

As a result of the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and its compliance requirements, MISO's generator interconnection queue has seen a fluctuation in natural gas interconnection requests (Table 4.2-3). Data corresponding to year 2017 only includes natural gas requests for the first three quarters.

Year	Gas Requests (MW)	% Of All New Requests
2017	6,882	21.8%
2016	4,472	12.6%
2015	9,076	35%
2014	9,424	58%
2013	3,835	30%
2012	4,509	63%

Table 4.2-3: Recent-year natural gas requests

Furthermore, there are about 12.2 GW of solar generation interconnection in definitive planning phase (DPP) as of July 2017. This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic (PV) modules.

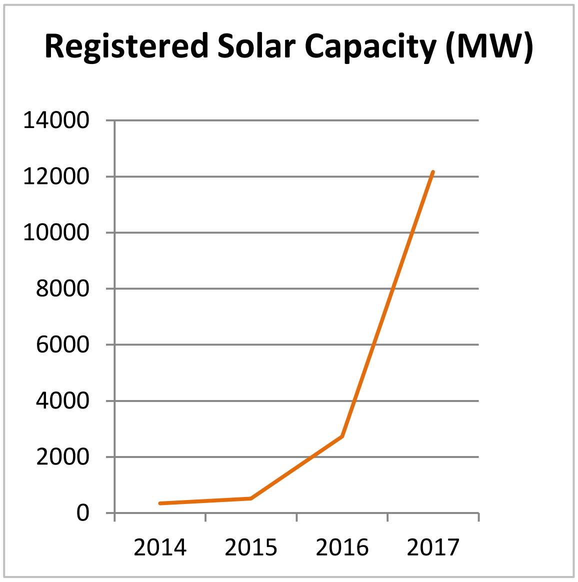


Figure 4.2-5: Solar capacity requests for MISO

Process Improvement

Over the past 12 years, the MISO Interconnection Process has evolved from first-in, first-out methodology to first-ready, first-served methodology to expedite the generation project queue lifecycle and maintain system reliability.

With significant changes implemented in the latest 2017 Interconnection FERC approved Queue Reform, which largely addressed backlogs in the generator interconnection queue and late-stage withdrawals of generator interconnection agreements, MISO expects that its new three phase process will allow Interconnection Customers to withdraw their Interconnection Requests earlier in the process and thus reduce restudies and delays in completing studies (System Impact and Facility Studies).

MISO continues to seek more opportunities to improve the queue process, while following basic guiding principles: reliable interconnection; timely processing; certainty in process; and Targeted Risk Allocation. The current drivers for this effort include re-studies caused by project withdrawals, evolving industry standards, more variable generation in the queue and changing technology.

MISO has reviewed the past process and study criteria, and identified areas for significant improvement. Process improvement focus areas that MISO continues to work on are:

- Compliance with new TPL-001-4 standards
- Consistency in the planning model
- Attachment Y process coordination
- Interconnection study timeline improvement
- Seams coordination
- Continuing to streamline the queue process with MISO energy market and capacity construct
- Exploring economic analysis-related options

4.3 Transmission Service Requests

Transmission Service Request (TSR) acquisition is the first step in creating schedules to move energy in, out, through or within the MISO market. When a customer or Market Participant submits and confirms a TSR on the MISO Open Access Same-Time Information Service (OASIS), it reserves transmission capacity. Long-term TSRs (one year or longer) must be evaluated for impacts to system reliability taking into account the deliverability of network resources in the MISO footprint. Short-term TSRs (less than one year) are evaluated based on the real-time Available Flowgate Capacity (AFC) values by MISO Tariff Administration.

Acquiring a TSR is the first step in creating schedules to move energy in, out, through or within the MISO market footprint.

From July 2016 to June 2017, MISO Transmission Service Planning processed 165 long-term TSRs (Figure 4.3-1) and completed 20 System Impact Studies for a total of 22 TSRs (Figure 4.3-1). Of these System Impact Studies, 12 TSRs were confirmed, six were refused/withdrawn, none executed a Facilities Study Agreement and four await the completion of a corresponding external Affected System Impact Study. Remainders of TSRs were either rollover TSRs, which don't require a system impact study, or withdrawn TSRs during the process.

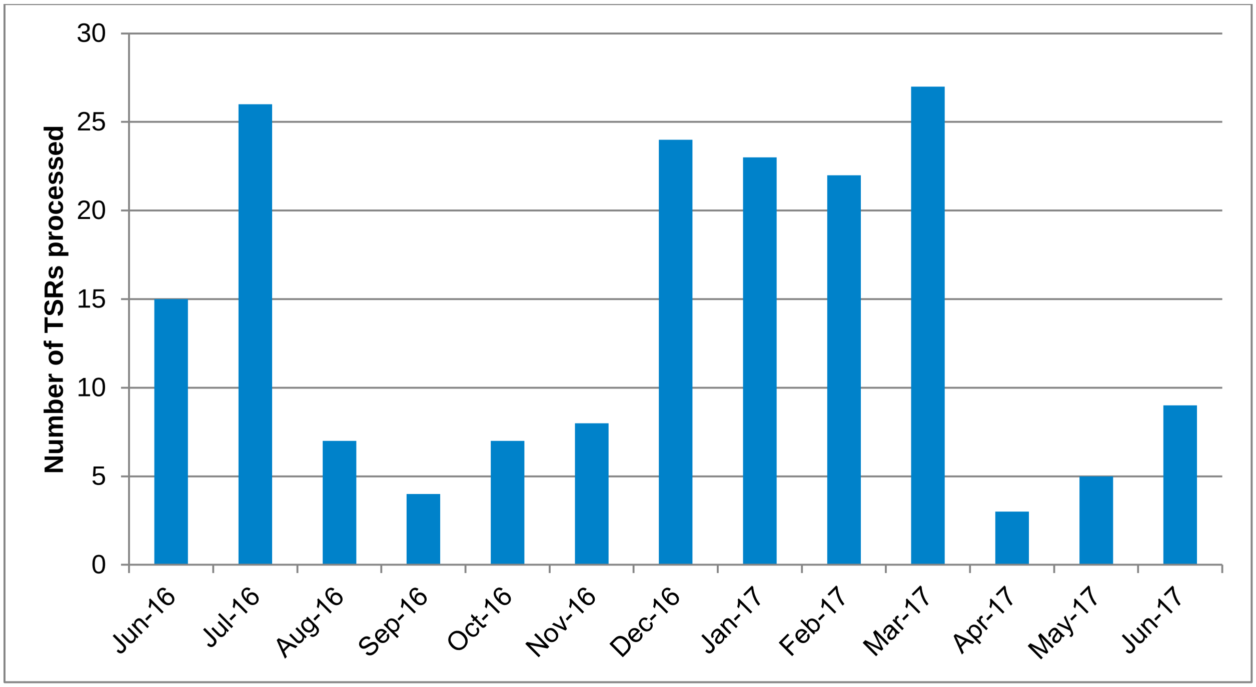


Figure 4.3-1: MISO Long-Term TSRs processed from July 2016 through June 2017

Long-term TSRs processed and evaluated by MISO planning staff are either Firm Point-to-Point or Network Transmission Service. Point-to-Point Transmission Service is the reservation and transmission of capacity and energy from the point(s) of receipt to the point(s) of delivery while Network Transmission Service allows a network customer to utilize its network resources, as well as other non-designated generation resources, to serve its network load located in the Transmission Owner's Local Balancing Authority area or pricing zone.

Short-term TSRs have a term of less than one year and can be firm or non-firm. Established MISO tools review the AFC on the 15 most-limiting constrained facilities on a TSR path to verify adequate capacity. If the AFC is positive for all 15 constrained facilities, the request is likely to be approved. Negative AFC on one or more of the 15 constrained facilities results in either a counter-offer or denial.

New long-term TSRs are processed based on queue order and type in the Triage phase (Figure 4.3-2). A TSR can be one of the three following types: original, a new TSR; renewal, a continuation of an existing TSR; or redirect, the changing of the source and/or sink of an existing TSR.

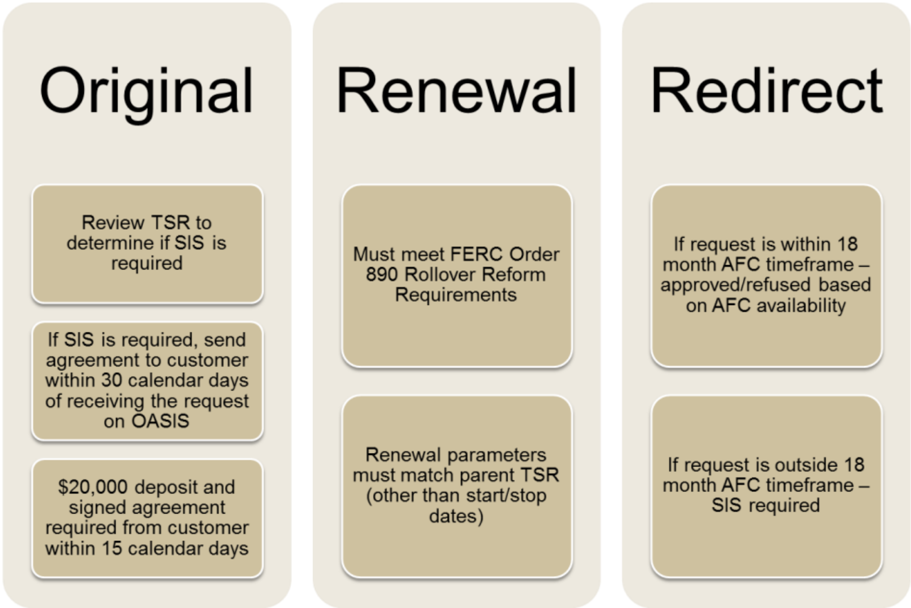


Figure 4.3-2: TSR triage phase processing

If a System Impact Study (SIS) is needed and the transmission customer returns the executed study agreement and deposit, MISO must complete the study within 60 calendar days from the time the agreement and deposit are received. MISO can accept the TSR and request specification sheets from the transmission customer if no constraints are identified in the study or if partial capacity can be granted. A Facilities Study is required if constraints are identified in the SIS and the customer choses to move forward with the TSR.

MISO then sends out a Facility Study Agreement within 30 calendar days for the customer to return along with a study deposit if they would like to move forward. If the agreement and deposit are not received, the TSR is refused. The Facility Study provides the costs and schedules to build upgrades required to mitigate the constraints identified in the SIS. Once complete, the customer has the option to take a reduced amount of transmission service, as identified in the SIS, proceed with a Facility Construction Agreement (FCA), or withdraw the TSR.

If the customer signs the FCA, the identified upgrades are included in MTEP Appendix A as Transmission Delivery Service Projects (TDSP). The cost of these upgrades is either directly assigned or rolled-in as per Attachment N of the Tariff. MISO can then request specification sheets and conditionally accept the TSR until all upgrades are in service.

Transmission Service Restriction

On March 28, 2014, the Federal Energy Regulatory Commission (FERC) accepted, over MISO's objection, a Transmission Service Agreement filed by Arkansas-based Southwest Power Pool (SPP), requiring MISO to pay SPP for any flow on SPP's transmission system above the existing 1,000 MW contract path between MISO North and MISO South.

MISO, SPP and Joint Parties reached a settlement that was subsequently filed with FERC in October 2015. The settlement provisions regulate the firm and non-firm utilization of the MISO North-MISO South contractual path from the date of acceptance of the settlement by FERC. The settlement was accepted by FERC in January 2016.

MISO instituted a contract path limit in TSR studies (in addition to the flow-based limitations) for the TSRs going across the MISO South-MISO North interface in both directions. An OASIS document has been posted to list out the latest contract path limit and the source sink combinations that are restricted. This document will be updated as/when the contract path rating is updated in future.

4.4 Generation Retirements and Suspensions

The permanent or temporary cessation of operation of generation resources can significantly impact the reliability of the transmission system. The MISO Attachment Y process provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

The MISO Attachment Y provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

Under the Tariff provisions, MISO may require the asset owner to maintain operation of the generation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC, Regional or Transmission Owners' (TO) planning criteria. In exchange, the generator will receive compensation for its applicable costs to remain available. SSR costs are paid by the loads in areas that benefit from the SSR generation. An SSR is considered a temporary measure where no other alternatives exist to maintain reliability until transmission upgrades or other suitable alternatives are completed to address the issues caused by the unit change in status.

Attachment Y Requests and Status

MISO received five new Attachment Y Notices (650 MW) for unit retirement/suspension during the first five months of 2017 (Figure 4.4-1). In the same period (January-May) in 2016 MISO received five Attachment Y retirement/suspension notices (1,929 MW) (Figure 4.4-1). MISO completed assessments and resolved a total of nine Attachment Y Notices (2,166 MW) for unit retirement/suspension in the first five months of 2017 (Figure 4.4-2).

Attachment Y activity remains fairly consistent over the year as asset owners move forward in the face of economic and pending regulatory pressures despite uncertainty in policy implementation. The activity is expected to continue at a regular pace as implementation plans become more clearly defined.

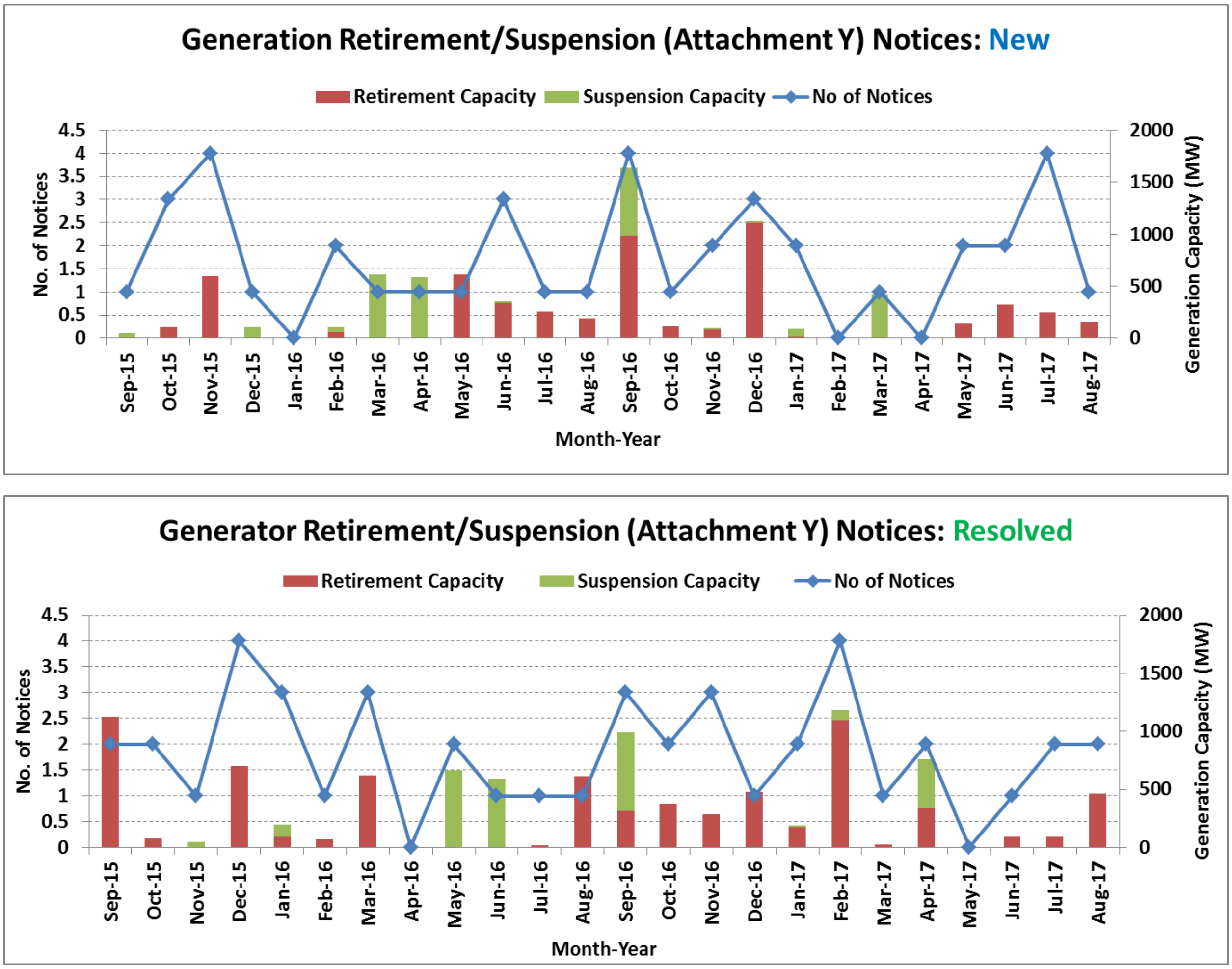


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 574 MW of generation capacity is retiring in 2017 and an additional 735 MW of generation capacity will retire in 2018 (Figure 4.4-2). This includes 257 MW of coal generation, 299 MW of gas generation and 18 MW of oil generation that is approved for retirement in 2017 and 735 MW of coal generation in 2018.

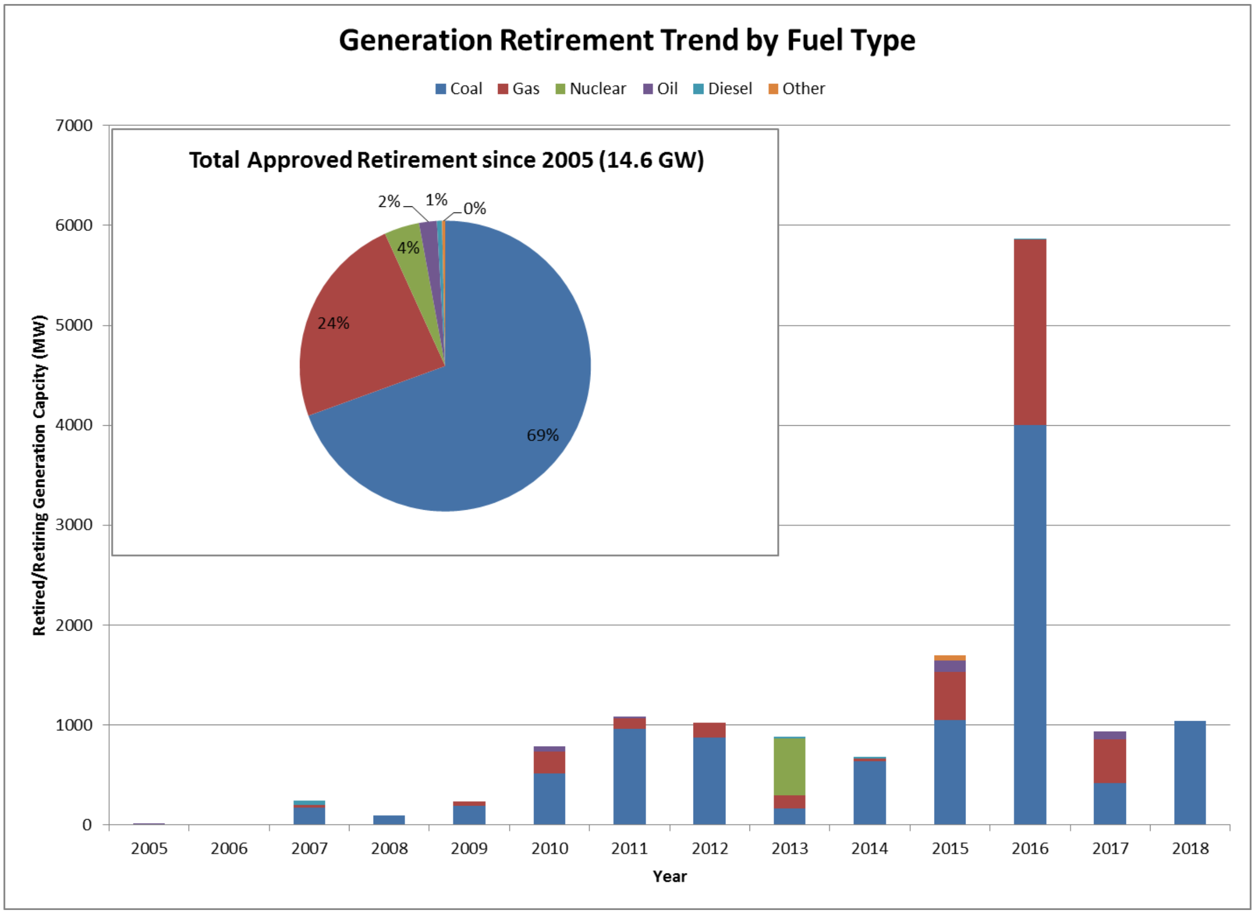


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2017 Activity with FERC, Tariff Changes

Independent Market Monitor Recommendation

In early 2017, MISO began efforts to enhance Attachment Y Tariff provisions to address Independent Market Monitor (IMM) Recommendation 2013-14 related to alignment of the Planning Reserve Auction (PRA) and the Attachment Y process governing retirements and suspensions. MISO has proposed an approach for more flexibility in retirement decisions that is currently under stakeholder review at the Planning Advisory Committee (PAC) and Resource Advisory Sub Committee (RASC).

The proposed Tariff changes include a more streamlined process for all Attachment Y notices to be submitted as suspension requests with rescission rights for until the start of the third full planning year following the submittal. Resource owners would maintain interconnection service until the end of the rescission period or the effective date of retirement if the rescission rights have been waived.

Generation Resources are provided more opportunity to participate in the PRA and base retirement decisions on the outcome of the PRA results. The proposed approach seeks to remove barriers to PRA participation by allowing the resource to continue operation even after MISO approves the Attachment Y Notice.

MISO will to continue to work with the Planning Advisory Committee to finalize a Tariff language that is expected to be filed with FERC by the end of the year.

SSR Agreement Activity

Since the inception of the SSR program in 2005, MISO has implemented 10 SSR Agreements with only one agreement currently remaining active for Teche Unit 3 (Figure 4.4-3).

> **Teche 3 (335 MW)** – The owner of the Teche plant in Louisiana requested to retire Unit 3 on April 1, 2017, and MISO determined that Teche Unit 3 is needed as an SSR unit until projects are implemented in the 2018 timeframe. The initial term of the SSR Agreement was established for April 1, 2017, to April 1, 2018.

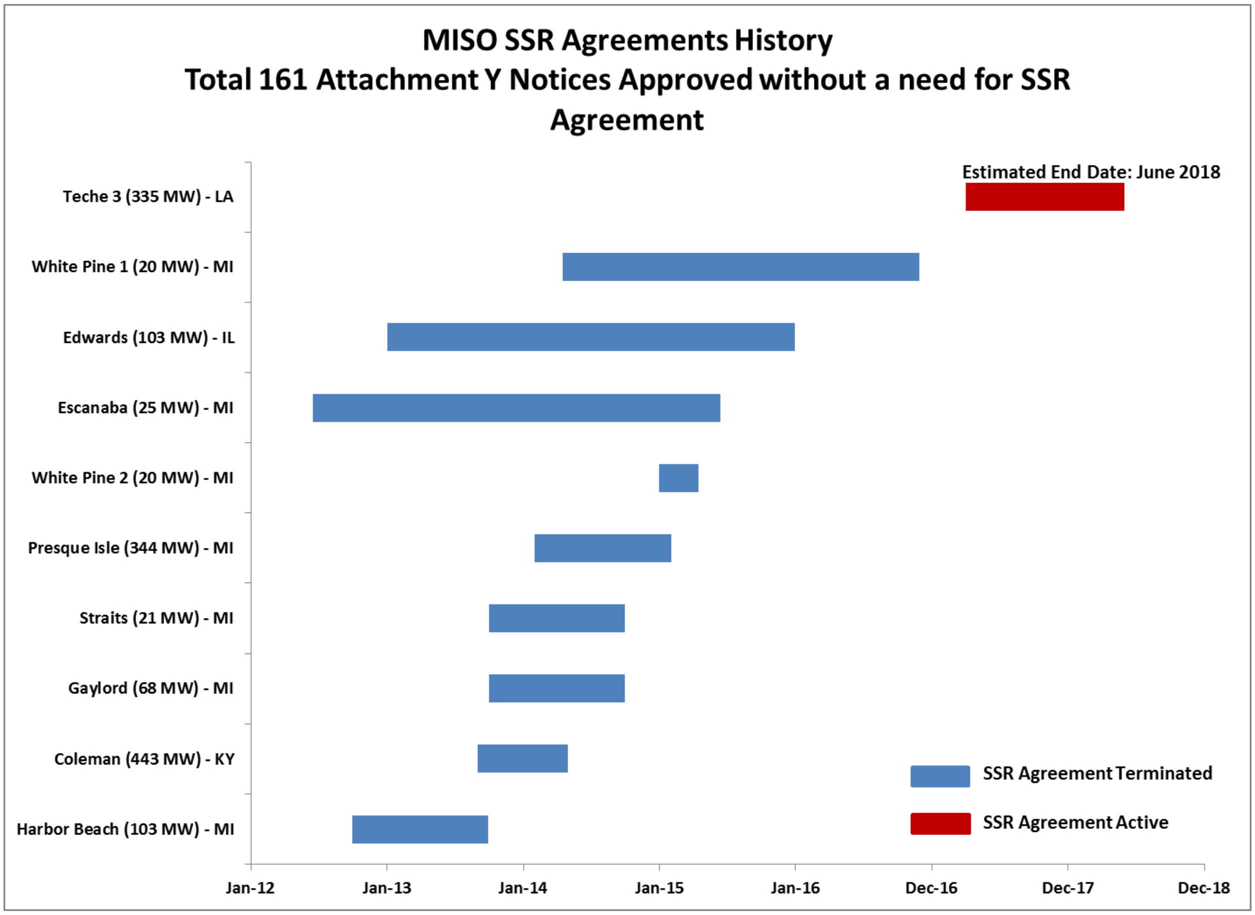


Figure 4.4-3: SSR history

Process

Market participants that own or operate generation resources seeking to retire or suspend operation of a generator are required to submit an Attachment Y Notice to MISO at least 26 weeks prior to the effective date of the change in status (Figure 4.4-4). MISO performs a reliability analysis with the participation of the TOs to determine if any violations of applicable NERC and TO planning criteria are caused by the unit retirement/suspension.

Within a 75-day period, MISO provides a response to the market participant indicating the study conclusion. MISO will approve the Attachment Y Notice if there are no violations of applicable planning criteria or if the issues are resolved by a planned upgrade. Any unresolved issues are presented in a stakeholder-inclusive process to evaluate alternatives that would avoid the need for an SSR contract.

If reliability issues are found in the study, MISO convenes an open stakeholder review of the Attachment Y issues and alternatives through Universal Non-disclosure Agreement (UNDA) and Critical Energy

Infrastructure Information (CEII)-protected Technical Study Task Force meetings. Alternatives that provide comparable benefit to retaining the SSR unit are considered and evaluated for effectiveness in relieving the violations and include such options as new/re-powered generation, reconfiguration, remedial action plans or Special Protection Schemes, demand response and transmission reinforcements. If an alternative is available, the Attachment Y Notice is approved. If the alternative does not eliminate all the violations of reliability criteria that require the need for the SSR Unit, MISO and the market participant will negotiate the terms of the SSR Agreement, which will be filed with FERC prior to the effective date. The agreement is subject to an annual review and renewal to allow the opportunity to terminate the need for an SSR Agreement if an alternative becomes available. Attachment Y information is considered confidential unless a reliability issue is identified in the study or the owner has otherwise publicly disclosed the information.

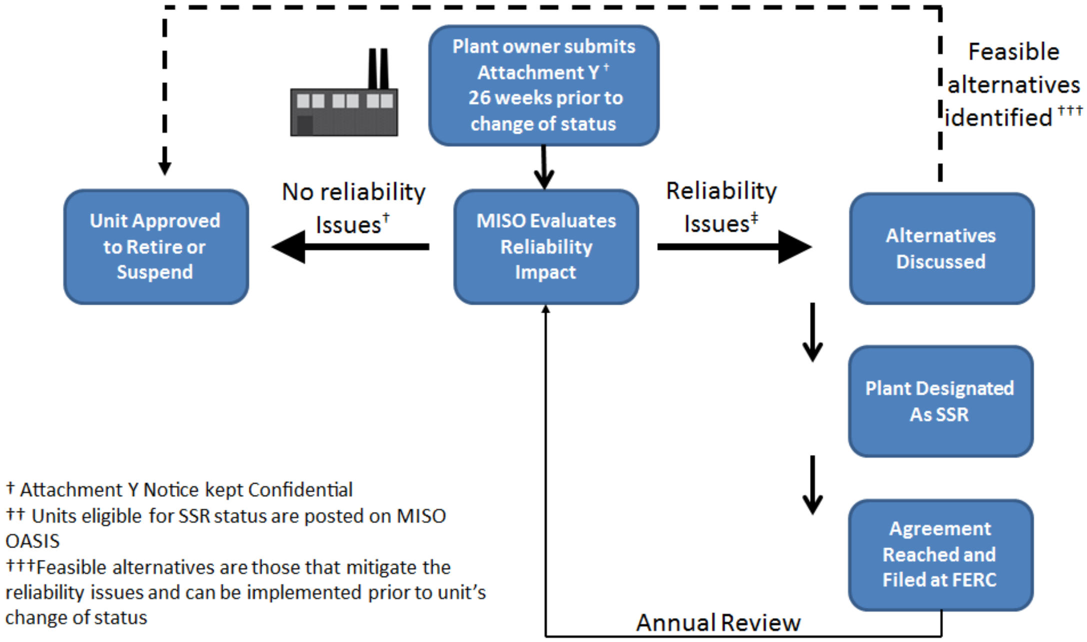


Figure 4.4-4: MISO Attachment Y process

4.5 Generator Deliverability Analysis

MISO performs generator deliverability analysis as a part of the MTEP17 process to ensure continued deliverability of generating units with firm service, including Network Resource Interconnection Service (NRIS). Results of the assessment are based on an analysis of near-term (five-year) summer peak scenario.

A total of 1,285 MW of deliverability is restricted in the near-term (five-year) summer peak scenario.

Analysis results revealed 15 constraints that restrict existing deliverable amounts and all require mitigation (Table 4.5-1) in the MTEP17 near-term scenario. Constraints observed that are restricting generation beyond the established network resource amounts will be mitigated. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

Table 4.5-1 shows the preliminary list of constraints requiring mitigation. These constraints, and their associated mitigation, will be discussed through the MTEP18 study process.

- “Overload Branch” is caused by bottling-up of aggregate deliverable generation
- “Area” is the Transmission Owner of the facility

Overloaded Branch	Area
Henry Co. 138 kV - New Castle 138 kV	DEI
Amber 138 kV - Donalds 138 kV	METC
Pere Marquette 138 kV - Amber 138 kV	METC
Pere Marquette 138 kV - Lake County 115 kV	METC
Gaylord 69 kV - Joberg 69 kV	METC
Sidney Transformer 230 kV - Sidney 230 kV	NPPD/WAPA
Batesville 161 kV - Tallhache 161 kV	TVA
GRE Maple 69 kV - GRE Maple 69 kV	GRE
Nashwauk 115 kV - 14L Tap 17 115 kV	MP
Dobbin 138 kV - Spring Branch 138 kV	EES
Spring Branch 138 kV - Deer Lake 138 kV	EES
Lewis Creek 138 kV - Sheawil 138 kV	EES
Sheawil 138 kV - FW Pipe 138 kV	EES
Esso 230 kV - Delmont 230 kV	EES
Star 115 kV - Menden Hall 115 kV	EES-EMI

Table 4.5-1: MTEP17 Near-term Preliminary Constraints that Limit Deliverability

FERC Order 2003 mandated that “Network Resource Interconnection Service provides for all of the network upgrades that would be needed to allow the Interconnection Customer to designate its Generating Facility as a Network Resource and obtain Network Integration Transmission Service. Thus, once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades”[18] to be funded by the Interconnection Customer.

[18] FERC Order 2003 Final Rule, paragraph 756: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9746398

Constraints recognized as needing mitigation were identified in the 2022 scenario (Table 4.5-1). Deliverability was tested only up to the granted network resource levels of the existing and future network resource units modeled in the MTEP17 2022 case. No new interconnection service is granted through the annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

> Once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades.

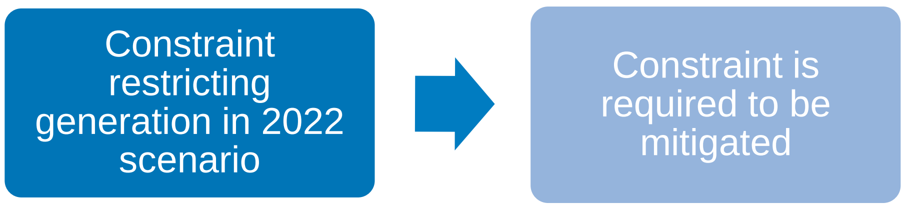
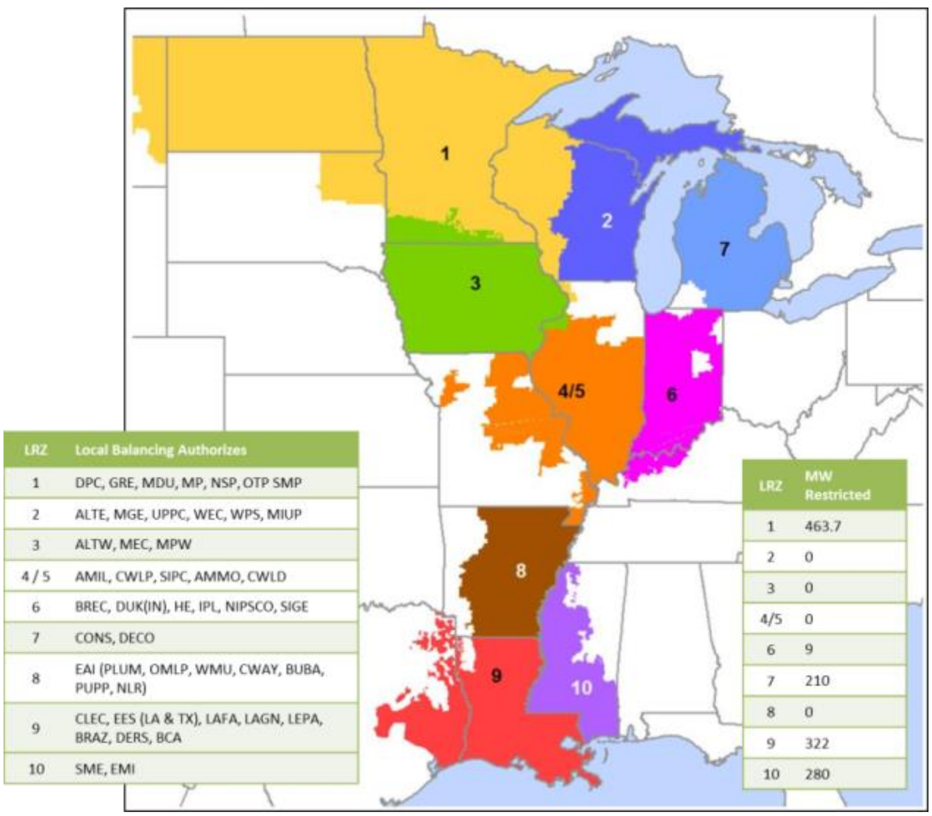


Figure 4.5-1: MTEP Deliverability Study Process Overview

The total MW restricted varies in the near term and is summarized by Local Resource Zone (Figure 4.5-2).



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4 / 5	AMIL, CWLP, SIPC, AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI (PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR)
9	CLEC, EES (LA & TX), LAFA, LAGN, LEPA, BRAZ, DERS, BCA
10	SME, EMI

LRZ	MW Restricted
1	463.7
2	0
3	0
4/5	0
6	9
7	210
8	0
9	322
10	280

Figure 4.5-2: Local Resource Zones (LRZ)

MTEP17 Mitigation

MTEP17 near-term (five-year) summer peak deliverability analysis results showed constraints that require mitigation. Preliminary mitigations submitted to alleviate limitation are shown in (Table 4.5-2). These projects, along with any other mitigation identified for the constraints will be reviewed by stakeholders in the MTEP18 planning process and recommended for approval as appropriate. A mitigation stated as TBD already has verbal mitigation submitted with project submission pending.

Overloaded Branch	Area	Mitigation (MTEP ID)	Notes
Nashwauk 115 – 14L Tap 115 kV	MP	9646	Mitigated by Targeted Appendix A project
Esso 230 – Delmont 230 kV	EES	9793	Mitigated by Targeted Appendix A in MTEP18
Star 115 – Mendenhall 115 kV	EES	13865	Mitigated by Targeted Appendix A in MTEP18
Lewis 138 kV - Sheawil 138 kV	EES	13864	Mitigated by Target A project
Sheawil 138 kV - FW Pipe 138 kV	EES	13864	Mitigated by Target A project
GRE Maple 69 kV - GRE Maple 69 kV	GRE	14145	Mitigated by Target B project
Pere Marquette 138kV – Lake County 138kV	METC	13574	Mitigated by MTEP C proposed project

Table 4.5-2: Preliminary projects to alleviate constraints that limit deliverability of Network Resources

MTEP16 Mitigation

MTEP16 near-term (five-year) summer peak deliverability analysis results showed four constraints that require mitigation. Mitigation was submitted for each of these constraint to alleviate limitation. Table 4.5-3 shows the project provided for each of the four constraints requiring mitigation.

Overloaded Branch	Area	MW Restricted	Mitigation (MTEP ID)
Markland 138 kV - He Belle Terra 138 kV	DEI	10.6	7961
Stout CT 138 kV - Stout North 138 kV	IPL	12.08	11523
Coughlin 138 kV - Plaisance 138 kV	CLEC	511.83	9716
La Crosse 69.0 kV - West Salem 69.0 kV	XEL	31.13	Rating Update

Table 4.5-3: MTEP16 projects submitted to alleviate constraints that Limited Deliverability of Network Resources during that cycle

Changes incorporated in MTEP17

MTEP17 applied three modifications into the Baseline Generator Deliverability analysis to better align the process for granting Network Resource Interconnection Service through the queue process and the MTEP Baseline Generator Deliverability analysis. The changes were initially presented at the May 2015 Planning Subcommittee meeting.

Changes implemented in MTEP17 are:

- Energy Resource with Transmission Service Requests will be considered for mitigation if service is limited
- The "Top 30" generator list will focus on a plant basis rather than unit basis
- Base dispatch of generators will not exceed the sum of the dispatch on a local balancing authority (LBA) basis

Energy Resource with Transmission Service Requests mitigation will be specifically identified. Transition deliverability studies identified deliverable MWs and the remaining were allocated to the non-deliverable bucket. Through transitional studies, MISO emphasized no loss of transmission service. In MTEP16 and previous years the TSRs were included in the base case. In MTEP17 constraints identified due to Energy Resources with Transmission Service Requests will require mitigation. The change is being made to ensure that services granted are kept whole concurrently.

The "Top 30" list will focus on a plant basis rather than a unit basis. Historically, through deliverability analysis, generators that contributed to constraints are limited to the most impactful 30 units (with some caveat for remote offline generators). In MTEP16, and previously for Baseline Generator Deliverability analysis, the placeholder was assigned based on generators that had separate buses assigned, which is generally on a unit basis. In MTEP17 the placeholder assignment is based on a plant, rather than a unit. The change is being made to capture generators at the same physical location that are expected to contribute to the same constraints. Previously, units at the same plant may have partially contributed and the remaining portion not participated.

Base dispatch will not exceed the sum of the dispatch on an LBA basis. The goal of deliverability analysis is to ensure that generators are not bottled up. The starting dispatch for deliverability studies is an LBA-level dispatch, which means that Network Resources within individual LBAs dispatched in merit order to serve LBA network load. The base dispatch will be adjusted to model all Network Resources at the same percentage of output, to the extent that all of the Network Resources are not dispatched in the starting case. The percentage may be different for each LBA. This adjustment will ensure that on an LBA basis, extreme exports are not applied causing a potential reduction in Network Resources in another LBA. The deliverability study will then ramp up the Network Resources simultaneously based on impacts to identified facilities. This ensures that the units are not bottled up and will continue to be studied on a footprint-wide basis to internal MISO load.

4.6 Long Term Transmission Rights Analysis Results

MTEP evaluates the ability of the transmission system to fully support the simultaneous feasibility of Long Term Transmission Rights (LTTR). To that effect, MISO performs an annual review of the drivers of the LTTR infeasibility results from the most recent annual Auction Revenue Rights (ARR) Allocation and determines the sufficiency of MTEP upgrades to resolve this infeasibility.

MTEP provides for reliable and economic use of resources, reducing the likelihood of infeasible LTTRs.

MISO details the financial uplift associated with infeasible LTTRs for its regions (Table 4.6-1) and documents planned upgrades that may mitigate the drivers of LTTR infeasibility identified using the annual Financial Transmission Rights (FTR) auction models (Table 4.6-2).

As part of the annual ARR allocation process, MISO runs a simultaneous feasibility test to determine how many ARRs, in megawatts, can be allocated. This test determines to what extent LTTRs granted the prior year can be allocated as feasible LTTRs in the current year. The remaining unallocated LTTRs are deemed infeasible, and their cost is uplifted to the LTTR holders.

For 2017-2018 planning year, the total LTTR payment is $441.9 million. The LTTR infeasibility uplift ratio is 3.65 percent (Table 4.6-1).

Region	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
MISO-wide	436.4	$441.9	$16.1	3.65%

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2017 Annual ARR Allocation

Infeasibility in any annual allocation of LTTRs can occur due to near-term conditions and their impact on the ARR allocation models. However, as MTEP projects are completed, reliability limits are eliminated and economic congestion is reduced across the transmission system. This provides for the more reliable and efficient use of resources associated with LTTRs in general, resulting in reduced infeasibility of financial rights over time.

Planned mitigations associated with limited LTTR feasibility are listed in Table 4.6-2. Binding constraints are filtered for those with values greater than $250,000. Other constraints will continue to be monitored in the annual allocation process for feasibility status. MISO will coordinate with its Transmission Owners to investigate constraints in the MTEP17 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2017	Fall 2017	Winter 2017	Spring 2018	Grand Total	Planned Mitigation
GRIMES - MT ZION 138 FLO GRIMES 345/ 230 AT4 PONDER AT1	$473,390	$187,790	$524,891	$1,219,093	$2,405,164	10487 - Western Region Economic Project - ISD 2019
PONDER - LONGMIRE 138 FLO CONROE BULK - PONDER 138	$189,474	$293,036	$154,659	$264,538	$901,707	Appendix B in MTEP17 12090 Reconductor Ponderosa to Longmire ISD 2021 I
REDGUM - NATCHEZ SES 115 FLO NATCHEZ S - VIDALIA - PLANTATION 115	$324,573	$136,198	$150,319	$215,128	$826,218	13867- Target A in MTEP18, Natchez SES - Red Gum 115 kV: Rebuild line, ISD 2020
GRIMES - MT ZION 138 FLO CONROE BULK - PONDER 138	$-	$263,483	$263,483	$-	$615,380	10487 - Western Region Economic Project -- ISD 2019
DELHI_E - CARSRD 115 FLO BAXTER WILSON - PERRYVILLE 500	$158,150	$205,118	$19,619	$147,726	$530,613	MTEP Project 12040
ARK NU - MABELVALE 500 FLO ARK NU PLEASANT HIL 500	$86,527	$89,990	$174,655	$153,636	$504,809	N/A
GRIMES - MT ZION 138 FLO GRIMES - BENTWATER 138	$-	$416,524	$-	$-	$416,524	10487 - Western Region Economic Project - ISD 2019
SHADELAND-LAFAYETTE SOUTH 138 FLO WESTWOOD - W LAFAYETTE 138 (13806A)	$234,806	$-	$114,124	$44,517	$393,448	Project 9963: It has been withdrawn as short term ratings were available
BOGALUSA-ADAMS CREEK 230 FLO MCKNIGHT - FRANKLIN 500	$165,721	$90,308	$63,015	$72,671	$391,715	N/A
WABASH RIVER-TERRE HAUTE WATER 138 FLO DRESSER - TERRE HAUTE EAST 138	$356,308	$3,846	$3,866	$-	$364,020	Dresser - Wabash River 138 kV line should provide some relief. Project got approved in MTEP14 but got delayed. Its ISD is: March 2017
TUBULAR - DOBBIN 138 FLO GRIMES 345/230 AT4 PONDER AT1	$41,244	$137,401	$7,456	$130,576	$316,676	12096 - Dobbin Reconfigure - ISD 2020
WESTWOOD 345/138 kV TR FLO WESTWOOD 345/138 T2	$65,073	$33,148	$190,868	$19,172	$308,261	N/A
MARBLEHEAD N 161/138 TR1 FLO MAYWOOD-HERLEMAN 345	$120,342	$31,332	$84,857	$51,827	$288,359	MTEP MVP, ISD 2019
DRESSER-ALLENJCT 138 FLO WORTHINGTON 345/138 TR4	$272,466	$-	$-	$-	$272,466	Dresser - Wabash River 138 kV line should provide some relief. Project got approved in MTEP14 but got delayed. Its ISD is: March 2017
TALISHEEK 6 to BOGALUSA 230 FLO MCKNIGHT - FRANKLIN 500	$50,580	$88,988	$19,689	$107,393	$266,650	N/A
BATESVILLE 230/115 AT1 FLO BATESVILLE - L S POWER 230	$159,933	$-	$37,168	$67,810	$264,910	N/A

Table 4.6-2: Infeasible uplift breakdown by binding constraints from the 2017 Annual FTR Auction

Book 1 / Transmission Studies

Section 5: Economic Analysis

5.1 Economic Analysis Introduction

The MISO Value-Based Planning Process ensures transmission expansion plans minimize the total electric costs to consumers, maintain an efficient market, and enable state and federal public energy policy — all while maintaining system reliability. The Multi-Value Project Portfolio, approved in MTEP11, demonstrates the success of the Value-Based Planning Process. The Multi-Value Projects will save Midwest energy customers more than $1.2 billion in projected annual costs and enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.[19]

MISO's Value-Based Planning Process ensures the benefits of an economically efficient energy market are available to customers by identifying transmission projects that provide the highest value.

The objective of MISO's value-based planning approach is to develop cost-effective transmission plans while maintaining system reliability. Cost-effectiveness considers not only the capital cost of transmission projects but also the projected cost of energy (production cost) and generation capacity.

The Regional Generator Outlet Study (RGOS) which was completed in November 2009 offered_extensive analysis to determine an optimal balance point between transmission investment and generation production costs. The RGOS determined that expansion plans that minimized transmission capital costs, but had high production costs through the use of less-efficient local generation resources, yielded the highest total system cost. RGOS found the same high cost was present with expansion plans that minimized generation costs by siting generation optimally, but away from load centers, and invested heavily in regional transmission development. The bottom-up, top-down planning approach evaluates both locally identified transmission projects (bottom-up) and also regional transmission development opportunities (top-down) to find the dynamic balance that minimizes both transmission capital costs and production costs (Figure 5.1-1).

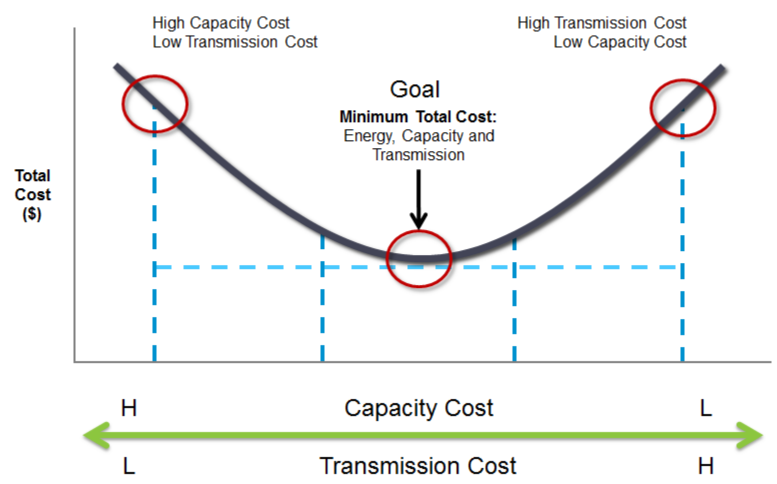


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

[19] Source: Multi-Value Project Portfolio - MTEP 2011

Since MTEP06, the MISO planning process has used multiple future scenarios to model out-year policy, economic and social uncertainty. While MISO's analysis may influence market participants' out-year resource plans, MISO is not a regional resource planner. Instead MISO's futures provide multiple reasonable resource forecasts based on probable out-year conditions including, but not limited to: fuel costs; fuel availability; environmental regulations; demand and energy levels; and available technology. Regional resource forecasts are developed based on a least-cost methodology. Generation and demand-side management resources are geographically sited based on a stakeholder resource planner vetted hierarchy. MISO regional resource forecasts include consideration of thermal units, intermittent resources, demand-side management and energy efficiency programs. These regional forecasts ensure that out-year planning reserve margins are maintained.

Policy assessment requires a continuing dialogue between MISO, local entities and regulatory bodies. This dialogue must identify new and existing policies and discuss how local entities intend to comply with them. It should also identify any potential regional needs or solutions to policy-driven issues. State and federal energy policy requirements and goals are the primary drivers and the first step of MISO's Value-Based Planning Process.

Value-Based Planning Process

The objective of MISO's Value-Based Planning Process is to develop the most robust plan under a wide variety of economic and policy conditions as opposed to the least-cost plan under a single scenario. While the best transmission plan may be different in each policy-based future scenario, the best-fit transmission plan — or most robust — against all these scenarios should offer the most value in supporting the future resource mix.

A planning horizon of at least 15 years is needed to accomplish long-range economic transmission development, since it is common for large projects to take 10 years to complete. Performing a credible economic assessment over this time is a challenge. Long-range resource forecasting, powerflow and security-constrained economic dispatch models are required to extend to at least 15 years. Since no single model can perform all of the functions for integrated transmission development, the Value-Based Planning Process integrates multiple study techniques using the best software available, including:

- Energy Planning – PROMOD and PLEXOS
- Reliability Planning – PSS/E, PSLF and TARA
- Decision Analysis – GE-MARS, PROMOD and EGEAS
- Strategic Planning – EGEAS
- Resource Portfolio Development – EGEAS

MISO's Value-Based Planning Process is also known as the Seven-Step Planning Process (Figure 5.1-2). While the Value-Based Planning Process is chronologically sequenced, not all projects start at Step 1 and end at Step 7. For example, depending on scope, a project may begin with pre-existing assumptions or plans and therefore start in Steps 4 or 5. Generally, Steps 1 and 2 are performed only annually. The Value-Based Planning Process is cyclical, and therefore the outputs and project approvals from one cycle are used as inputs in the next cycle. Additionally, the Step 7 to Step 1 link serves as the bridge between planning and operations to refresh assumptions based on approved projects.

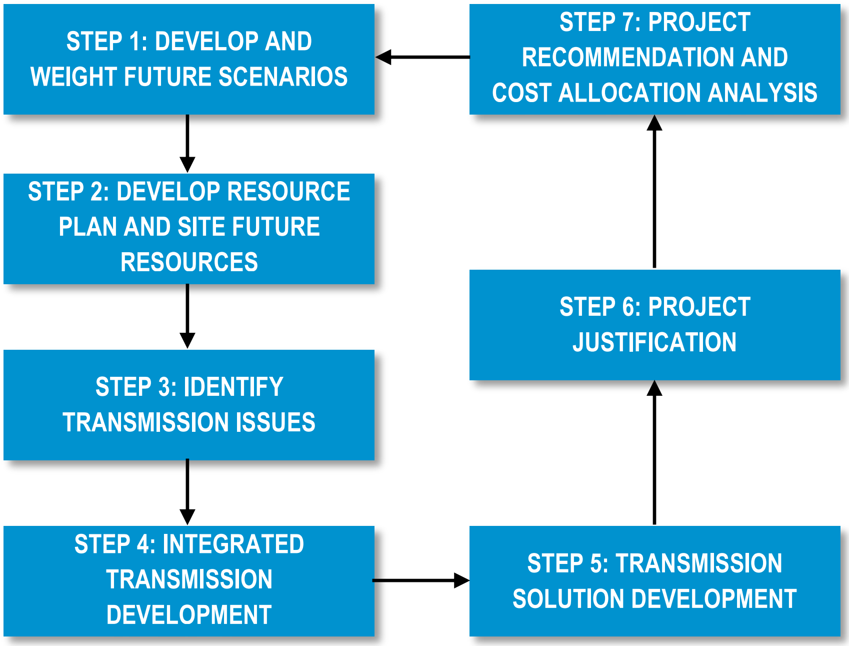


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

Step 1: Develop and Weight Future Scenarios

Scenario-based analysis provides the opportunity to develop plans for different future scenarios. A future scenario is a postulate of what could be, which guides the assumptions made about a given model. The outcome of each modeled future scenario is a generation expansion plan, or resource portfolio. Resource portfolios identify the least-cost generation required to meet reliability criteria based on the assumptions for each scenario.

Future scenarios and underlying assumptions are developed annually and collaboratively with stakeholders through the Planning Advisory Committee. The goal is a range of futures, linked to likely real-life scenarios, that provides an array of outcomes that are significantly broad, rather than a single expected forecast.

A more detailed discussion of the assumptions and methodology around the MTEP17 future scenarios is in Chapter 5.2: MTEP Future Development.

Step 2: Develop Resource Plan and Site Future Resources

Resources forecasted from the expansion model for each of the future scenarios are specified by fuel type and timing; however, these resources are not site-specific. Future resource units must be sited within all planning models to provide an initial reference position five to 20 years into the future. Completing the process requires a siting methodology tying each resource to a specific bus in the powerflow model. A guiding philosophy and rule-based methodology, developed in conjunction with industry expertise, is used to site forecasted resources. The siting of regional resource forecast units is reviewed annually by the Planning Advisory Committee. A more detailed discussion of the siting methodology around each MTEP17 future is in Chapter 5.2: MTEP Future Development.

Step 3: Identify Transmission Issues

A key component of value-based transmission planning is the identification of Transmission Issues. In most cases, Transmission Issues addressed by value based planning include economic value opportunities and public policy compliance issues. Economic value opportunities typically include transmission congestion issues where solutions are desired to eliminate costly redispatch. In the value based planning process, these congestion issues are identified in a bifurcated process using a) a list of top congested flowgates derived from Market Congestion Planning Studies and b) a range of economic opportunities derived from indicative congestion relief analysis for each defined Future.

This analysis typically includes simulation of a non-constrained case and a constrained case, where the non-constrained case relaxes transmission constraints and the constrained case enforces transmission constraints. This analysis reveals such information as total congestion costs, congestion costs by constraint, and geographic-based congestion patterns, and can be used to inform the value based planning process both at a high level and low level. The low level view tends to identify specific constraints and data associated with those constraints such as shadow prices, binding hours, and binding levels. The lower level view is often considered alongside the historic congestion data. The high level view provides insight into geographic pricing and congestion patterns for potential corridors for new transmission development.

Step 4: Integrated Transmission Development

After Transmission Issues are identified, stakeholders will be given the opportunity to submit solutions to these issues. The solution submission window typically opens in January/February timeframe and lasts for six to eight weeks. Solution ideas are used to inform the planning process. MISO, while working with stakeholders, may modify solution ideas throughout the value based planning process.

MISO may also submit its own solution ideas to address Transmission Issues. MISO will continue to work with stakeholders to ensure solutions properly address the Transmission Issues.

Step 5: Transmission Solution Evaluation

The first step in transmission solution evaluation is to screen each of the transmission solution ideas. Projects that meet a pre-defined threshold (typically a 0.9 Benefit-to-Cost ratio) are evaluated further. These projects then undergo a full present value analysis which utilizes all modeled years and future assumptions to come up with a future weighted benefit-to-cost ratio. Projects that are still performing well through this phase then undergo contingency screening to identify any new flowgates that may be produced as a result of the project. Any new flowgates that are identified will be added to the project’s event files and the full present value analysis will be conducted again to see how much of an impact the new flowages have on a project’s benefits. This process can be iterative, especially as transmission solutions evolve.

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

Once robustness testing has been conducted, it may be necessary to develop appropriate portfolios of transmission projects to complete the overall, long-term plan. One key consideration in consolidating and sequencing plans is the need to maintain flexibility in adapting to future changes in energy policies. In order to create a transmission infrastructure that will support changes to resources and market requirements with the least incremental investment and rework, a comprehensive plan, which offers the most benefit under all outcomes, is developed from elements of the best-performing preliminary plan.

Step 6: Project Justification

A business case will be created for all projects including a detailed analysis of benefits and costs. While the project justification is continuously developed throughout the solution evaluation step, additional scenarios or sensitivities may be developed which evaluate the impact certain future assumptions may have on a project. These sensitivities help to ensure that the projects which proceed to recommendation are robust. These sensitivities may include, but are not limited to, changes in generation siting and future retirement assumptions. Additional sensitivities are developed with the input and guidance of stakeholders throughout the process.

Step 7: Project Recommendation and Cost Allocation Analysis

MISO, with input from stakeholders and considering all analysis performed to determine benefits and costs, will recommend projects to the MISO Board of Directors for approval. This recommendation will be only for those projects that have been shown to meet or exceed all criteria for type of project being recommended. Projects meeting or exceeding all project type criteria will be recommended to the MISO Board of Directors in the last quarter of each MTEP cycle, or as otherwise defined in the MISO Tariff.

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment (Table 5.1-1). In general, the cost allocation method is dependent on whether the transmission is needed to maintain reliability, improve market efficiency, interconnect new resources and/or support energy policy mandates and goals. Cost allocation mechanisms are developed and revisited in a collaborative and open stakeholder process through the Regional Expansion Criteria and Benefits (RECB) Working Group.

Allocation Category	Driver(s)	Allocation to Beneficiaries
Market Efficiency Project	Reduce market congestion when benefits exceed costs by 1.25 times	Distributed to Cost Allocation Zones commensurate with expected benefit; 345 kV and above 20 percent postage stamp to load
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by transmission customer; Transmission Owner can elect to roll-in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10 percent postage stamp to load
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	Postage Stamp to Load
Market Participant Funded	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy or some combination of the three	Paid for by Market Participant
Baseline Reliability Project	NERC Reliability Criteria	Local Pricing Zone

Table 5.1-1: Summary of MISO Cost Allocation mechanisms

MISO's Value-Based Planning Process continues to evolve to better integrate different planning functions, take advantage of new technology and meet stakeholder needs, in both scope and complexity. Enhancements to the existing value-based planning process to accommodate Order 1000 requirements have been identified and implemented through a robust stakeholder process, including:

- Identification and selection of transmission issues through a multifaceted needs assessment upfront, encompassing both public policy needs and economic congestion issues/opportunities
- Open and transparent transmission solution idea solicitation with a formalized form to document and track solutions
- Development of an integrated transmission development process to categorize issues identified, screen solution ideas, refine solution ideas and formulate most-cost-effective projects

In MTEP17, MISO's Value-Based Planning Process is exemplified in the MTEP Future Development (Chapter 5.2), and Market Congestion Planning Study - South (Chapter 5.3).

5.2 MTEP Futures Development

Scenario-based analysis provides the basis for developing MTEP Futures resulting in economically feasible transmission plans. MTEP Futures are a stakeholder-driven postulate of what could be. With the increasingly interconnected nature of organizations and federal interests, forecasting a range of plausible futures greatly enhances the planning process for electric infrastructure. The futures development process provides information on the cost-effectiveness of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios.

Previously, future scenario definitions were developed annually; however, the MTEP process has historically resulted in very similar futures with gas price and load growth variations year over year. Rather than continue to develop similar futures, MISO implemented a new futures process beginning with MTEP17[20]. Under the new process, futures will be evaluated annually and a decision made with input from stakeholders as to whether futures need to be wholly redesigned or merely updated with current fleet changes and fuel and demand forecasts.

The goal of MTEP Futures is to bookend uncertainty by defining a wide range of potential outcomes. Futures are intended to be long-term and consider not only outcomes that could come to fruition within the next five years, but rather plan for uncertainty that could affect our industry in the next 15 years. To accomplish this goal, MISO in coordination with stakeholders developed three futures – Existing Fleet, Policy Regulations and Accelerated Alternative Technologies - for the MTEP17 cycle (Figure 5.2-1).

MTEP 2017 Future	Existing Fleet	Policy Regulations	Accelerated Alternative Technologies
Carbon Reductions *From 2005 Levels*	Current levels: ~14%	25%	35%
Demand and Energy	Low (10/90)	Base (50/50)	High (90/10)
Natural Gas Price *Nominal Dollars/MMBTU*	Base –30%	Base	Base +30%
Demand Side Additions *By Year 2031*	EE: 0.2 GW DSM: 3 GW	EE: 3 GW DSM: 4 GW	EE: 9 GW DSM: 7 GW
Renewable Additions *By Year 2031*	5 GW	22 GW	52 GW
Generation Retirements *By Year 2031*	Coal: 8 GW Gas/Oil: 16 GW	Coal: 16 GW Gas/Oil: 16 GW	Coal: 24 GW Gas/Oil: 16 GW

Figure 5.2-1: MTEP17 Future key attributes

MTEP Futures and their associated assumptions are developed with high levels of stakeholder involvement. As a part of compliance with the FERC Order 890 planning protocols, MISO-member

[20] See September 9th PAC meeting materials process discussion:
https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=207650

stakeholders are encouraged to participate in Planning Advisory Committee (PAC) meetings to discuss transmission planning methodologies and results. Scenarios are regularly developed to reflect items such as shifts in energy policy, changing demand and energy growth projections, generation fleet changes and/or changes in long-term projections of fuel prices.

Detailed MTEP17 capacity expansion results and assumptions are presented in Appendix E2[21].

Futures Narratives

Existing Fleet Future

The Existing Fleet Future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. No carbon regulations are modeled, though some reductions are expected due to age-related retirements – 9 GW of coal and 16 GW gas and oil – and renewable additions driven at the very least by renewable portfolio standards and goals. Natural gas prices remain low due to increased well productivity and supply chain efficiencies. Footprint-wide, demand and energy growth rates are low to model a more static system with no notable drivers of higher growth; however, as a result of low natural gas prices, industrial production along the Gulf Coast increases. Low natural gas prices and static economic growth reduce the economic viability of alternative technologies. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable and enforceable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled.

Other Existing Fleet Future features include:

- Demand and energy growth rates are modeled at half of the level equivalent to a 50/50 forecast
- Starting natural gas prices consistent with industry long-term reference forecasts are reduced by 30 percent
- The Low Growth demand response, energy efficiency and distributed generation penetration level programs developed by the Applied Energy Group (AEG) are allowed for selection in EGEAS
- Non-nuclear generators will be retired in the year the age limit is reached; 55 years for oil and gas, 65 years for coal. Nuclear units are assumed to have license renewals granted and remain online unless there are firm known retirements in the base model.
- All new unit capital costs increase at inflation.

Policy Regulations Future

The Policy Regulations Future is designed to capture the effects of current economic growth with average energy costs and medium gas prices. All current state-level RPS and EERS mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are incorporated.

Other Policy Regulations Future features include:

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast
- Starting natural gas prices are consistent with industry long-term reference forecasts
- The Existing Programs Plus demand response, energy efficiency and distributed generation penetration level programs developed by the AEG are allowed for selection in EGEAS
- Non-nuclear, non-coal generators will be retired in the year the age limit is reached. To capture the expected effects of environmental regulations on the coal fleet, 16 GW of coal units will be retired at least at the 65 year age and sooner reflecting economics and to target the 25 percent

[21] Futures developed for MTEP 17 will reflect a broader range of portfolio changes not specifically tied to the Clean Power Plan considering the stay of the CPP.

aggregate MISO fleet CO_2 reduction from the 2005 Baseline emissions of 505 million short tons. Nuclear units are assumed to have license renewals granted and remain online.

- Maturity cost curves for renewable technologies applied reflecting some advancement in technologies and supply chain efficiencies

Accelerated Alternative Technologies Future

The Accelerated Alternative Technologies Future represents a robust economy that drives technological advancement and economies of scale resulting in a greater potential for demand response, energy efficiency and distributed generation as well as lower capital cost for renewables reflected in the maturity cost curves. Age-related retirements will be applied to all units along with units that have either already retired or publicly announced they will retire. To capture the expected effects of environmental regulations on the coal fleet, 24 GW of coal unit retirements are modeled, some at the 65-year coal retirement age, others before, to target the 35 percent aggregate MISO fleet CO_2 reduction from the 2005 Baseline emissions of 505 million short tons.

Other Accelerated Alternative Technologies Future features include:

- Robust economy leads to increased demand & energy consumption modeled at 150 percent of the level equivalent to a 50/50 forecast. Footprint wide, demand and energy growth rates are high due to a robust economy; however, as a result of high natural gas prices, industrial production along the Gulf Coast decreases.
- Starting natural gas prices consistent with industry long-term reference forecasts are increased by 30 percent
- The Clean Power Plan demand response, energy efficiency and distributed generation penetration level programs developed by the AEG are allowed for selection in EGEAS

Capacity Expansion Results

The future resource additions and retirements are shown in Figure 5.2-2. The Existing Fleet future levels of resources added are a direct correlation to the demand and energy growth assumption as well as known and assumed age-related retirements. Renewables are only added to meet RPS requirements, achieving 11 percent renewable energy in this low load growth of the future. Also, there is more selection of Combustion Turbine (CTs) over Combined Cycle (CCs) reflecting the need for more peaking capacity than energy-providing baseload units. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

The fleet changes in Policy Regulations show an increased buildout of CCs and renewables reflecting the need for lower CO_2 emitting replacements of the increased coal retirements as well as to meet the medium load growth and commensurate increase in needed RPS renewables, resulting in 16 percent renewable energy. In the Accelerated Alternative Technologies Future, the great increase in renewable additions is driven by a stricter CO_2 reductions defined by the future at the increased level of coal retirements and load growth reaching 26 percent renewable energy. The system sees double the nameplate capacity added per units retired. Much of the capacity need is driven by retired units with higher capacity credits being replaced by units with lower capacity credits such as renewables that are given a capacity credit of 50 percent for solar and 15.2 percent for wind in the Policy Regulations and Accelerated Alternative Technologies futures.

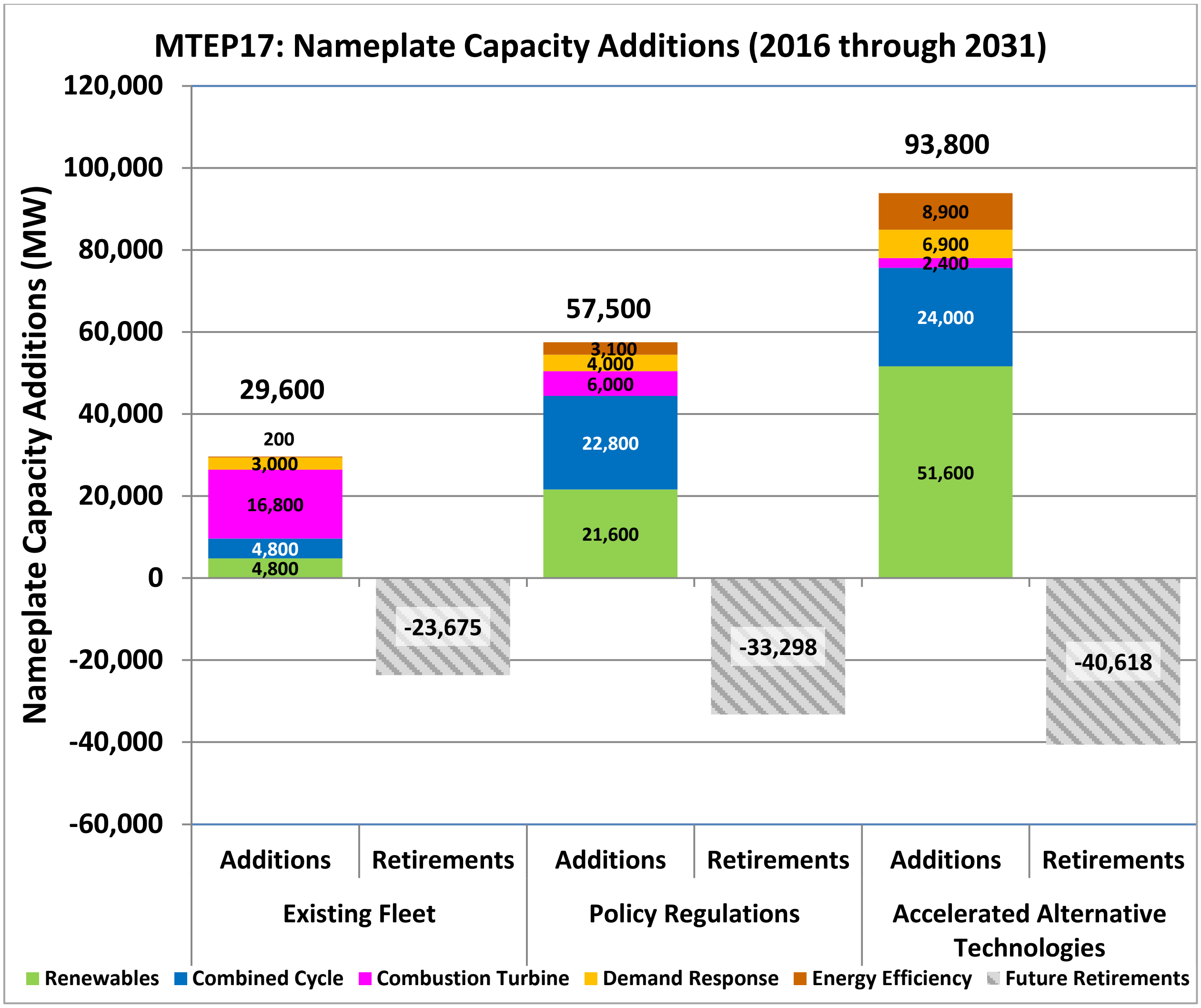
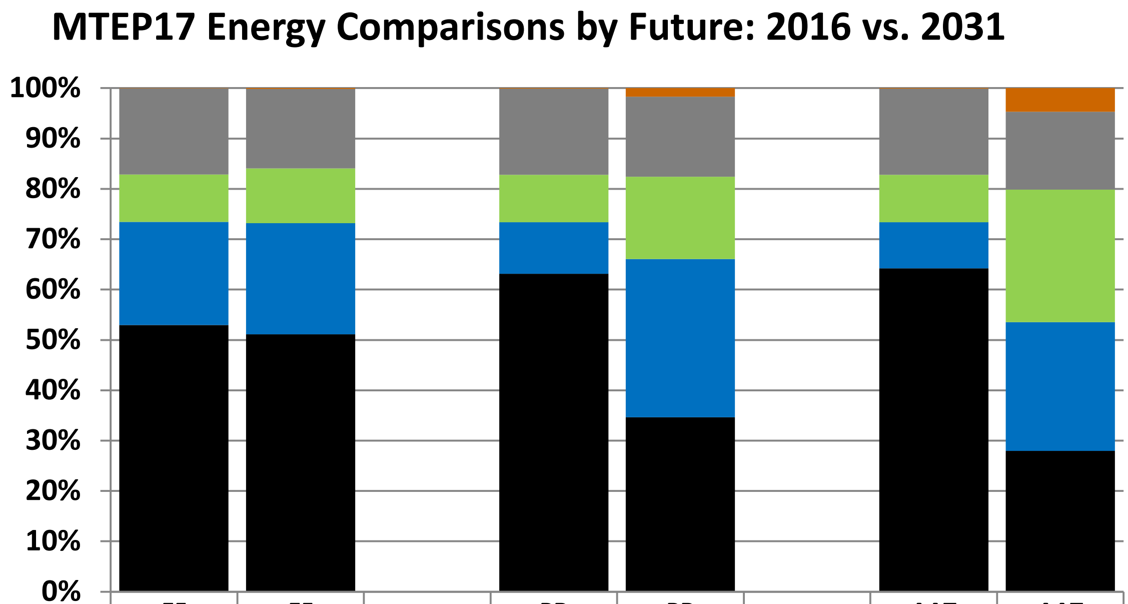


Figure 5.2-2: MISO nameplate capacity additions by future (2015-2030 EGEAS Model)[22]

The energy usage of the system is shown for each future in Figure 5.2-3. The chart shows the energy utilization of the system in the base year (2016) compared to the PROMOD final year (2031). For the Existing Fleet future, coal is dispatched at 53 percent in the base year while coal is dispatched at 63 percent and 64 percent in the Policy Regulations and Accelerated Alternative Technologies futures respectively. The driver for the difference in base year energy utilization is the higher starting natural gas prices. The higher gas price makes more coal resources get dispatched over gas resources but changes over time as coal retirements and CO_2 reductions increase.

[22] Due to coal plant retirements that have already occurred, only the additional amounts of modeled retirements are shown in the figure.



	EF 2016	EF 2031		PR 2016	PR 2031		AAT 2016	AAT 2031
DSM	0%	0%		0%	2%		0%	5%
Other	17%	16%		17%	16%		17%	15%
Renewable	9%	11%		9%	16%		9%	26%
Gas	20%	22%		10%	31%		9%	26%
Coal	53%	51%		63%	35%		64%	28%

Figure 5.2-3: Energy comparisons by future: 2016 versus 2031

Effective Demand and Energy Growth Rates

Many states have encouraged, and in some cases mandated, the use of demand-side management (DSM) technologies in order to reduce the need for investment in new power generation. To evaluate the potential of DSM within the footprint, MISO consulted with the AEG to develop various DSM programs tailored to each major Eastern Interconnection (EI) study region. These efforts are documented in Section 6.4: Demand Resource, Energy Efficiency and Distributed Generation of MTEP17, as well as the 2015 AEG report[23]. Specific modeling approaches for these programs are additionally highlighted in Appendix E2.

This AEG effort led to the development of 20-year forecasts for various types of DSM for the MISO region and the rest of the Eastern Interconnection. The study found DSM programs that have the potential to significantly reduce the load growth and future generation needs of the system at a varying degree of costs. Economic program selections are also detailed in Appendix E2 that detail these step 1 and step 2 futures development, modeling and siting efforts.

Table 5.2-1 shows the gross and net demand and energy growth rates for MTEP17 futures. As the demand response programs selected are dispatchable in the PROMOD model, the non-dispatchable energy efficiency programs selected are the only impacts netted out.

[23] AEG Report: https://www.misoenergy.org/Events/Pages/DREEDG20160208.aspx

MTEP17 Futures	Baseline Growth Rates		Effective Growth Rates	
	Demand	Energy	Demand	Energy
Existing Fleet	0.37%	0.40%	0.35%	0.39%
Policy Regulations	0.64%	0.65%	0.52%	0.56%
Accelerated Alternative Technologies	0.92%	0. 91%	0.86%	0.87%

Table 5.2-1: MTEP17 effective demand and energy growth rates

Siting Of Capacity

Generation resources forecasted from EGEAS are specified by fuel type and timing, but these resources are not site-specific. The process requires a siting methodology tying each resource to a specific bus in the powerflow model and uses the MapInfo Professional Geographical Information System (GIS) software. The Generation Interconnection Queue typically only indicates what capacity we can expect on the system in the next two-to-five years. Units that complete the queue process and have a signed Generator Interconnection Agreement (GIA) are assumed existing as of their slated in-service-date at the time the model is built and therefore get no additional forecasted generation. Those queue units under study without signed GIA’s typically have forecasted resources of the same type sited at them. Specific siting criteria by unit technology type are detailed in Appendix E2.

Renewable generation is sited at specific tiers developed using the Vibrant Clean Energy (VCE) study[24]. Similar to siting of other technologies, the initial renewable siting tiers are focused on queue sites, and then expand to site in areas with good output potential.

Demand Response programs are sited at the top 10 load buses for each PowerBase area per the programs selected in each major modeling region. The amount of starting DR capacity remains constant across all futures, but grows differently depending on the AEG programs used per future. More detailed siting guidelines, modeling methodologies and the results for the other futures are depicted in Appendix E2.

Figure 5.2-4 shows a map of the Existing Fleet Future Siting, Figure 5.2-5 shows a map of the Policy Regulations Future Siting and Figure 5.2-6 shows a map of the Accelerated Alternative Technology Future Siting.

[24] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=223249

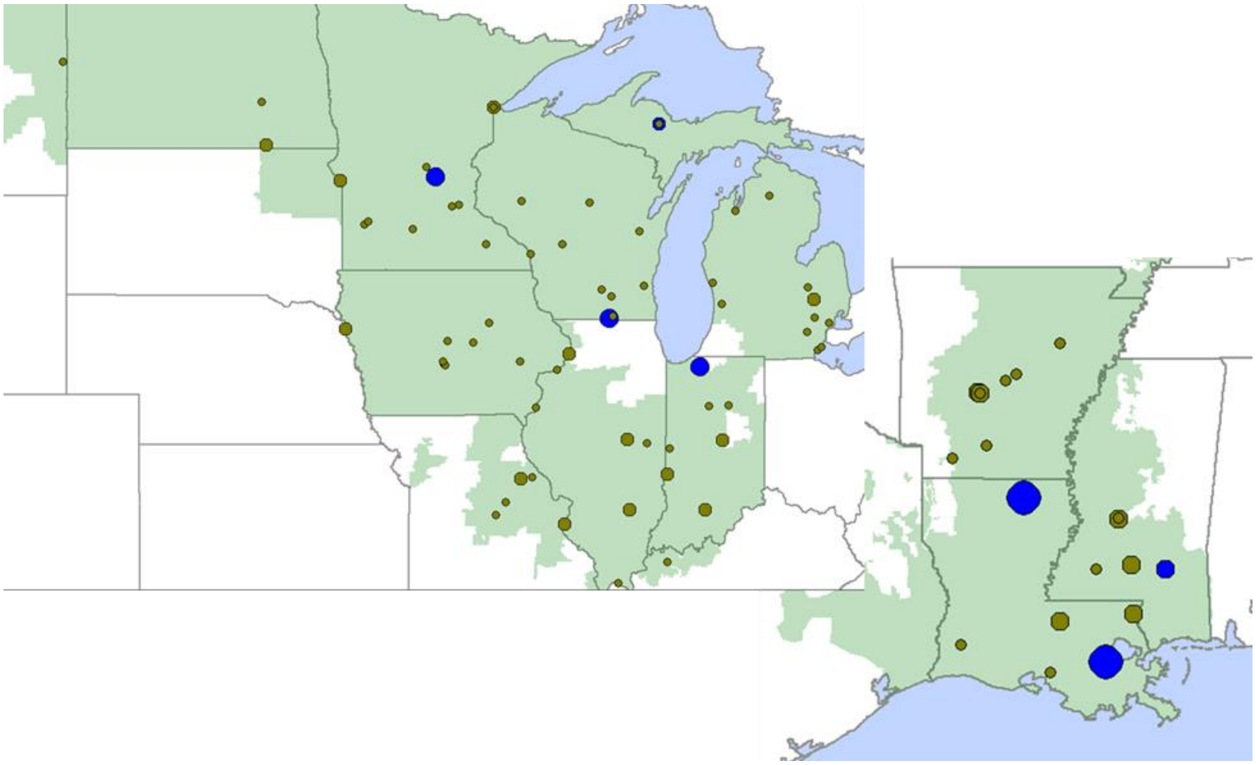


Figure 5.2-4: Existing Fleet Future Siting (MapInfo)

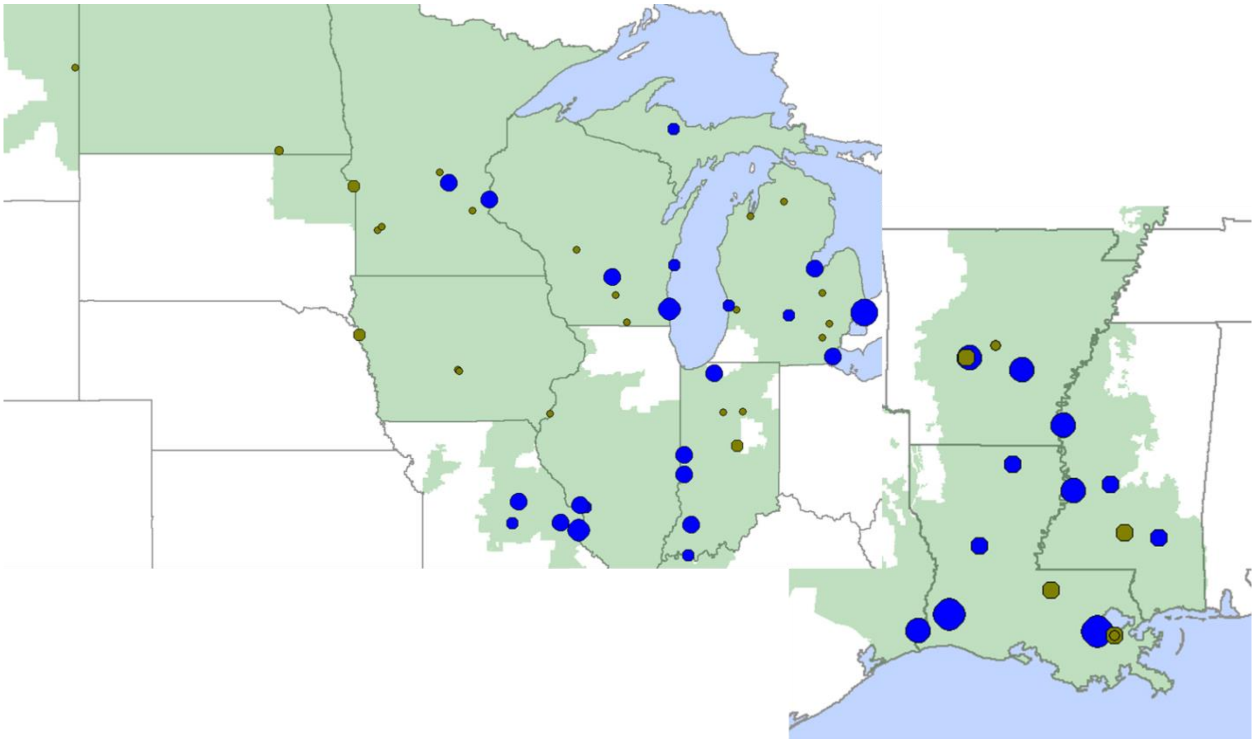


Figure 5.2-5: Policy Regulations Future Siting (MapInfo)

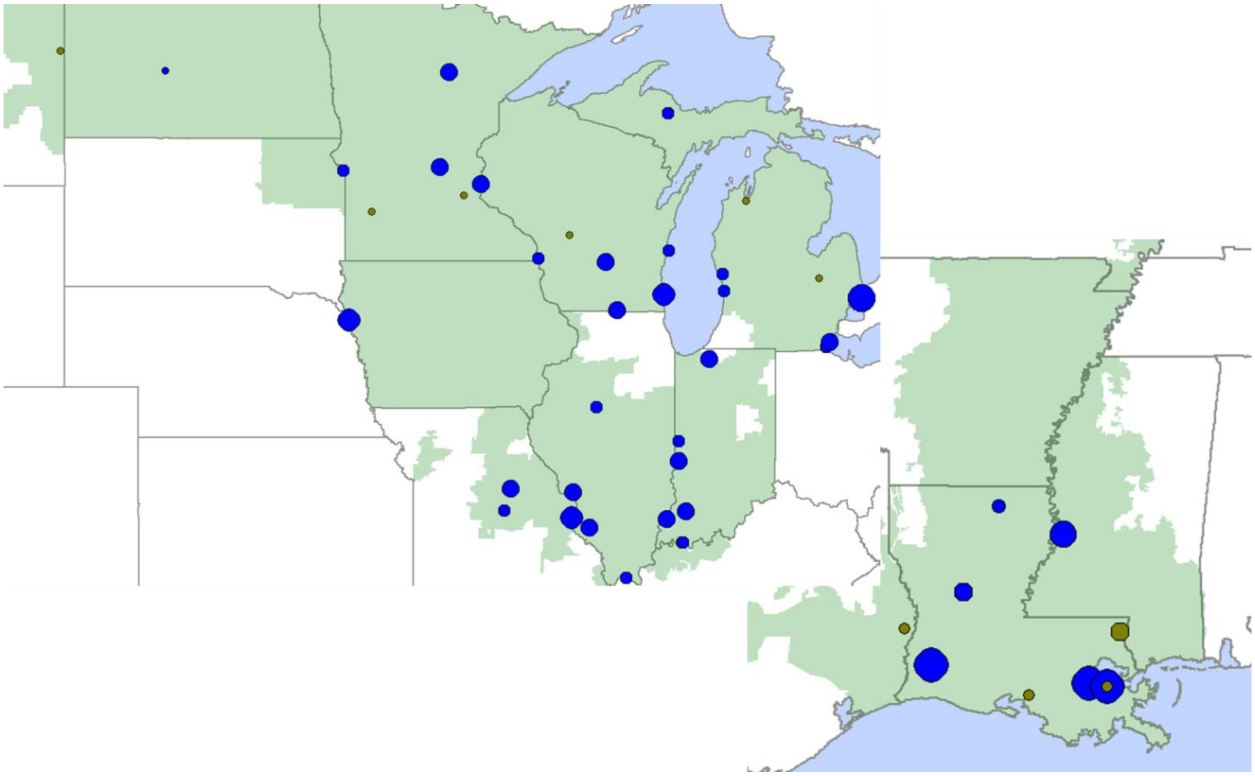


Figure 5.2-6: Accelerated Alternative Technology Future Siting (MapInfo)

5.3 Market Congestion Planning Study – South

Since its integration, the MISO Board of Directors has approved significant transmission investments in the MISO South region leading to a reduction in congestion. The 2017 MCPS study effort for the South region is built on the progress made during the previous MTEP cycles, which identified several congested flowgates and evaluated the applicable transmission solutions. The 2017 cycle focuses on five specific areas in MISO South: Amite South/Downstream of Gypsy (DSG); West of the Atchafalaya Basin (WOTAB)/Western; Local Resource Zone (LRZ) 8 (Arkansas); LRZ10 (Mississippi); and Remainder of LRZ9 (rest of Louisiana).

In the MTEP17 MCPS study effort, several solutions were designed in a collaborative effort between MISO and stakeholders. The solutions were tested for their robustness to address system needs under a variety of scenarios, embodied by the MTEP17 futures.

The following project candidate is recommended to the MISO Board of Directors for approval as a Market Efficiency Project:

- Hartburg – Sabine Junction 500 kV Economic Project ($129.7 M)
    - New 500/230kV substation
    - Re-configuring the existing Sabine – McFadden and Sabine – Nederland 230 kV transmission lines into the new substation
    - New 500kV line from Hartburg to New Substation
    - New 500/230kV 1200 MVA transformer at the new substation

The following project candidates are recommended to the MISO Board of Directors for approval as Other economic projects:

- Sam Rayburn – Doucette 138 kV Network Upgrade ($2.8 M)
    - Replace 26 transmission structures on the Sam Rayburn – Fork Creek – Turkey Creek – Doucette 138 kV transmission line path
    - This will increase these transmission line section ratings to 137 MVA from 112 MVA
- Carlyss Substation Equipment Upgrade ($0.5 M)
    - Replace two air break switches at Carlyss 138 kV substation to a minimum of 1,600 A
    - Upgrade the 138 kV bus and 230/138 kV autotransformer bay terminal equipment to at least 1,600 MVA
    - This will increase the Carlyss 230/138 kV transformer rating to 300 MVA from 243 MVA

MCPS Study and Process Overview

The goal of the Market Congestion Planning Study (MCPS) is to develop transmission plans that offer MISO customers better access to the lowest electric energy costs through the markets. From a regional perspective, the study seeks to identify both near-term transmission congestion and long-term economic opportunities and the appropriate network upgrades to enhance the efficiency of the market. The solutions may, therefore, vary in scale and scope, classified as either Economic Other Projects or Market Efficiency Projects. As an integral part of MISO's value-based planning, the MCPS looks to develop the most robust transmission upgrades that offer the highest future value under a variety of both current and projected system scenarios.

The MCPS begins with a bifurcated Need Identification approach to identify both near- and long-term transmission issues. The Top Congested Flowgate Analysis identifies near-term, more localized congestion while the longer-term Congestion Relief Analysis explores broader economic opportunities (Figure 5.3-1). Given the targeted focus of the MTEP17 MCPS, emphasis was placed on the top congested flowgate analysis. The congestion relief analysis will be employed in future, broader-scoped planning studies.

With the needs clearly defined, the study evaluates a wide variety of transmission ideas in an iterative fashion with both economic and reliability robustness considerations. The Project Candidate Identification phase includes: screening analysis to pinpoint the solutions with the highest potential; economic evaluation over multiple years and futures to assess robustness; and reliability analyses to ensure the projects do not degrade system reliability. Using this approach, optimal economic transmission upgrades (best-fit solutions) are identified to address market congestion. The solutions may be either cost shareable or non-cost shareable projects.

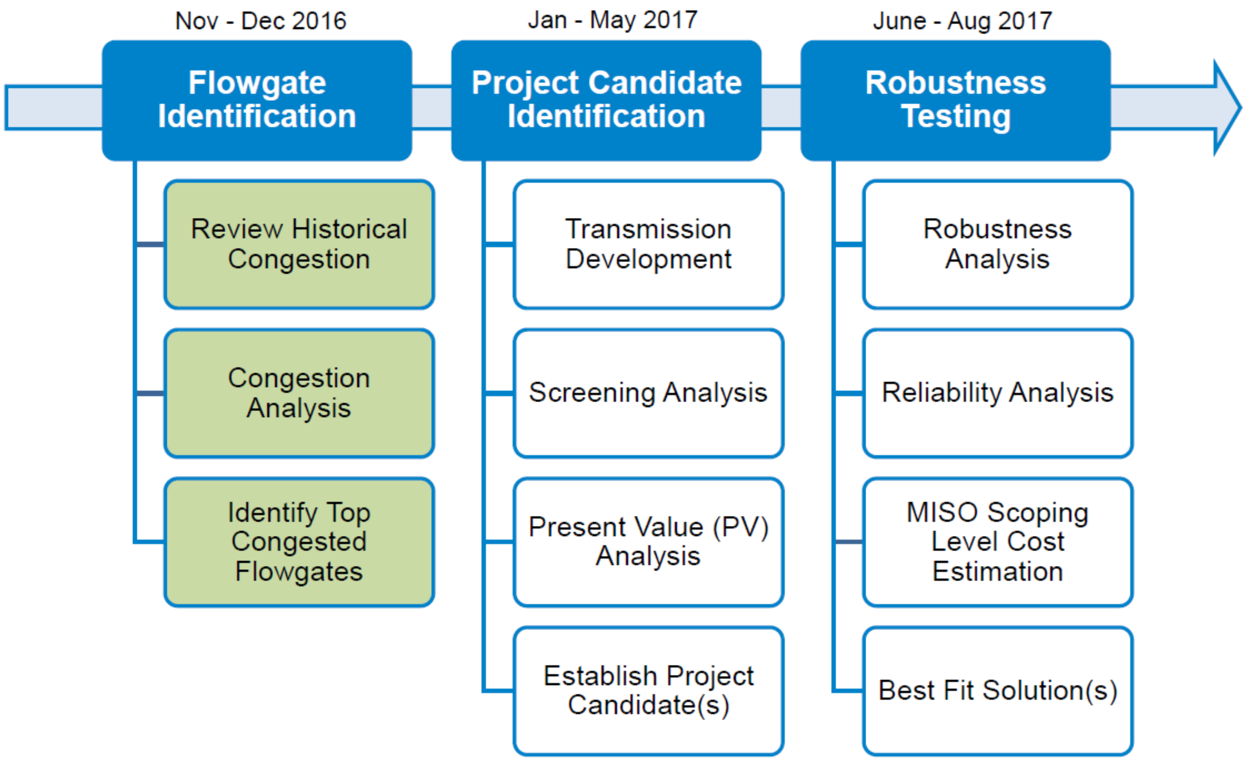


Figure 5.3-1: MCPS process overview

MISO Models and Futures

The production cost models utilized for this study are based on data from PROMOD Powerbase and the corresponding MTEP powerflow cases. The data is refreshed with the most current information and with the system variables (fuel cost, demand, etc.) reflecting the MTEP futures definitions. The agreed-upon future scenarios - Existing Fleet (EF), Policy Regulation (PR) and Accelerated Alternative Technologies (AAT) – each have a future weight for the MTEP17 MCPS study (Table 5.3-1).

MTEP17 Future	Future Weight (%)
Existing Fleet (EF)	40
Policy Regulation (PR)	40
Accelerated Alternative Technologies (AAT)	20

Table 5.3-1: MTEP17 MCPS South Future Weights

MISO assigned weights to each future, with input from the Planning Advisory Committee (PAC), as a reflection of the perceived probability of each future being actualized (see Chapter 5.2, MTEP Future Development).

Generation Sensitivity Scenarios

Through collaboration with Stakeholders, MISO developed and evaluated two additional generation sensitivity siting scenarios to better understand the impact that generation siting has on congestion and projects within each of the load pockets. The base future siting is referred to as Scenario 1.

In Scenario 2, all of the future Regional Resource Forecast (RRF) generation that was sited inside of the load pockets was moved to locations outside of the load pockets. Due to the differences in siting among the three different futures, the source and destination of the generation changes vary (Tables 5.3-2 to 5.3-4).

Powerbase Name	Scenario 1	Scenario 2
RRF MISO CC:001	Little Gypsy 230 kV	Wrightsville 500 kV
RRF MISO CC:006	Nelson 230/138 kV	Lake Catherine 115 kV
RRF MISO CC:060	Nine Mile 230 kV	Holland Bottoms 500 kV
RRF MISO CT:007	Sabine 138 kV	Hot Springs 115 kV
RRF MISO CT:010	Hartburg 230 kV	Hinds 230 kV
RRF MISO CT:011	Hartburg 230 kV	Hinds 230 kV
RRF MISO CT:016	Nine Mile 115 kV	Big Cajun 230 kV
RRF MISO CT:090	Sabine 230 kV	Couch 115 kV

Table 5.3-2: MTEP17 MCPS South generation Scenario 2 changes – AAT future

Powerbase Name	Scenario 1	Scenario 2
RRF MISO CC:001	Little Gypsy 230 kV	Wrightsville 500 kV
RRF MISO CT:007	Sabine 138 kV	Baxter Wilson 115 kV
RRF MISO CT:023	Sabine 138 kV	Baxter Wilson 115 kV
RRF MISO CT:048	Nine Mile 230 kV	Rodemacher 230 kV
RRF MISO CT:053	Sabine 230 kV	Gerald Andrus 230 kV
RRF MISO CT:058	Nine Mile 230 kV	Gerald Andrus 230 kV
RRF MISO CT:066	Nelson 138 kV	Baxter Wilson 115kV
RRF MISO CT:067	Nelson 138 kV	Franklin 500 kV
RRF MISO CT:090	Sabine 230 kV	Rodemacher 230 kV

Table 5.3-3: MTEP17 MCPS South generation Scenario 2 changes – EF future

Powerbase Name	Scenario 1	Scenario 2
RRF MISO CC:001	Little Gypsy 230 kV	Franklin 500 kV
RRF MISO CC:006	Nelson 230/138 kV	Holland Bottoms 500 kV
RRF MISO CC:039	Sabine 138 kV	Sterlington 500 kV
RRF MISO CT:014	Nine Mile 230 kV	Bailey 115 kV
RRF MISO CT:015	Nine Mile 230 kV	McClellan 115 kV
RRF MISO CT:016	Nine Mile 115 kV	Teche 138 kV
RRF MISO CT:023	Sabine 138 kV	Teche 138 kV
RRF MISO CT:053	Sabine 230 kV	Rex Brown 115 kV

Table 5.3-4: MTEP17 MCPS South generation Scenario 2 changes – PR future

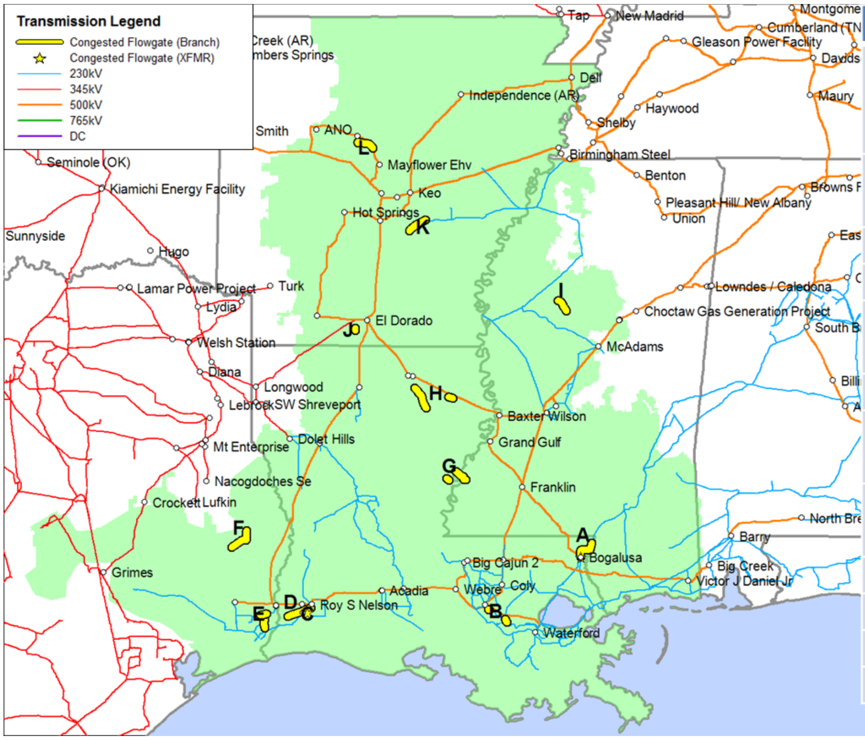
In Scenario 3, MISO utilized Entergy's issued generation request for proposals as a basis for siting future generation at Lewis Creek, Nelson and Michoud (Table 5.3-4).

Siting Location	Capacity (MW)	In-Service Year		
		AAT	EF	PR
Nelson 230/138 kV	1,000	2020		
Lewis Creek 230/138 kV	1,000	2021		
Michoud 115 kV	250	2019		

Table 5.3-5: MTEP17 MCPS South generation Scenario 3 generation siting

Top Congested Flowgate Analysis

The top congested flowgate analysis identifies system congestion trends based on both the historical market data and forecasted congestion. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams Figure 5.3-2.



ID	Monitored Element
A	Bogalusa 500/230 kV Transformer
	Adams Creek – Bogalusa 230 kV[1]
	Adams Creek – Angie 230 kV
B	St. Gabriel – AAC Corp 230 kV[1]
	Panama – Wilton 230 kV[1]
C	Carlyss 230/138 kV Transformer[2]
D	Mossville – Marshall 138 kV[1]
E	Chisholm – Sabine 230 kV[2]
	McLewis – Chisholm 230 kV[1]
F	Sam Rayburn – Fork Creek 138 kV[2]
G	Plantation – S. Ferriday Tap 115 kV
	Red Gum – Natchez 115kV
H	Carson Rd – Delhi 115 kV
	Swartz – Alto 115 kV
I	Greenwood – Greenwood 115 kV
J	Wyatt – Parnell Rd 115 kV
K	Woodward – Altheimer 115 kV
L	Morrilton East – Gleason 161 kV

Figure 5.3-2: Projected top congested flowgates in MISO South Region

The flowgates of interest are those with historical congestion and are projected to limit constraints throughout the 15-year study period. MISO finds these flowgates by examining:

- Historical day-ahead, real-time and market-to-market congestion
- Projected congestion identified through out-year production cost model simulations

The magnitude and frequency of congestion offers a strong signal to where transmission investments should be made.

Project Candidate Identification

Project candidate identification is a partnership between MISO and stakeholders to identify network upgrades that address the top congested flowgates. Solution ideas may be submitted by stakeholders or developed by MISO staff. The solution ideas include those designed to directly address specific flowgates, provide energy transfer paths, and/or to unlock economic resources by connecting import-limited areas to export-limited areas.

[25] These flowgates include multiple element contingencies (e.g. generator + transmission line events)
[26] These flowgates include single and multiple element contingencies (e.g. generator + transmission line events)

Given the potential for numerous transmission idea submissions, MISO developed a screening process to identify the most cost-effective solutions to relieve the congestion of interest. The screening does not preclude any solutions, but rather refines the pool of projects that will be analyzed in detail as MISO determines the optimal solution. Adjusting for model updates through the course of the study, the screening results are a good predictor of the projects' performance. The screening index for each solution was calculated as the ratio between the 15-year-out Adjusted Production Cost (APC) savings and the corresponding project cost:

$$\textit{Screening Index} = \frac{\mathbf{15}\ \textit{year out Future Weighted APC Savings}}{\textit{Solution Cost}\ \times \textit{MISO Aggregrate Annual Charge Rate}}$$

Any project with a screening index of 0.9 has the potential for a benefit-to-cost ratio greater than 1.25, the Market Efficiency Project (MEP) threshold. In addition to identifying the projects with the highest potential, the screening analysis provides valuable information that can be used to modify and improve the solutions that do not pass the screening. In general, transmission solutions do not pass the screening index threshold for one of at least three reasons: the solution does not relieve all of the congestion on a targeted top flowgate(s); the solution relieves congestion on one flowgate but increases congestion on other flowgate(s); or the solution relieves congestion but the project cost is high relative to benefit.

By considering the specific reason for a project's screening performance, the project can be refined to better address the congestion. Corresponding to the above three reasons, the refinement may include: expanding and/or reconfiguring a project; combining projects that address related flowgates; and pruning projects to keep the most effective elements. The refinement of the solutions properly considers the balance of achieving synergistic benefits and avoiding excessive transmission build-outs that produce diminishing returns.

This study phase determines the project candidates that move on to a more comprehensive analysis.

Robustness Testing

Once the preliminary project candidates are identified, an iterative process takes place between economic robustness evaluation and reliability assessment. Robustness testing identifies the transmission projects/portfolios that provide the best value under most, if not all, predicted future outcomes; the reliability assessment ensures system reliability is at least maintained.

Project Benefit and Cost Analysis

The MISO Tariff measures a MEP's benefit by the APC savings realized through the project under each of the MTEP future scenarios. APC savings are calculated as the difference in total production cost adjusted for import costs and export revenues with and without the proposed project in the transmission system. Given the five-year transition period following MISO South integration in 2013, the benefits for each project are counted only for the relevant MISO sub-region, North/Central or South. Data from three simulation years (2021, 2026 and 2031) are used as the basis for evaluating the project impact. A 20-year benefit is calculated by linearly interpolating and extrapolating from these three years. The total project benefit is determined by calculating the present value (PV) of annual benefits for the multi-future and multi-year evaluations.

As further detailed in Attachment FF of the MISO Tariff, a MEP must meet the following criteria:

- Have an estimated cost of $5 million or more
- Involve facilities with voltages of 345 kV or higher; and may include lower-voltage facilities of 100 kV or above that collectively constitute less than 50 percent of the combined project cost
- Benefit-to-cost ratio of 1.25

Although prescribed for MEPs, the above metric and analysis is used to evaluate all economic projects. To arrive at the best solution, projects with a benefit-to-cost ratio greater than 1.25 but not meeting all the MEP criteria are also considered.

Reliability Analysis

The reliability analysis uses a no-harm test to determine the impact of project candidates on the thermal, voltage and transient stability as well as the short circuit capability under system impact and contingent events. A project candidate passes the reliability no-harm test if there is no degradation of system reliability with the addition of the project.

The no-harm test compares the contingency analysis results between two models, a base model and a model including the project candidate, to find if any violations are worsened by the addition of the project candidate.

For the thermal analysis, the following sensitivities from the Economic Scenarios were evaluated:

- Sabine Units 1, 3 and 4 retired
- Future Load-Pocket Generation Siting (from MTEP17 Futures)

The no-harm test was performed on three cases (Table 5.3-5). NERC contingencies were also evaluated (Table 5.3-6).

Analysis Type	2022 Summer Peak	2022 Shoulder Peak	2022 Light Load	2027 Summer Peak
Steady State Thermal/Voltage	X			X
Voltage Stability				X
Transient Stability	X	X	X	

Table 5.3-6: Models utilized in no-harm analysis

Analysis Type	P0	P1	P2	P3	P4	P6
Steady State Thermal/Voltage	X	X	X	X		X
Voltage Stability				X		
Transient Stability	X	X			X	X

Table 5.3-7: Contingencies evaluated in no-harm analysis

Amite South/DSG

Congestion was identified in the Amite South load pocket, particularly on the import lines into the load pocket (Figure 5.3-3). In the event that an import line into the Amite South load pocket is out of service (N-1) along with the loss of a generator (G-1) inside the load pocket, flows shift to the remaining import lines. This causes heavy congestion as well as Voltage and Local Reliability (VLR) commitments in the Amite South and Downstream of Gypsy (DSG) load pockets. Further aggravating the congestion are the import limitations of the transmission system as well as the limited economic generation resources available inside the Amite South and DSG load pockets. Construction of additional import lines into Amite South or DSG would therefore help to alleviate congestion as well as VLR issues in this area and can provide easy access to economic generation in these load pockets.

Six projects were submitted to address congestion in Amite South and DSG load pockets. These projects aimed to address issues of increased transfer capabilities into the Amite South and DSG load pockets, as well as alleviating congestion within the load pockets. After the completion of screening and refinement, none of the projects produced adequate benefits to pass the screening criteria.

Since integration, the MISO Board has approved significant transmission investments in the Amite South and DSG load pockets. These transmission expansions led to a reduction in congestion and the remaining congestion in the area is not sufficient to justify robust and cost effective transmission solutions. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

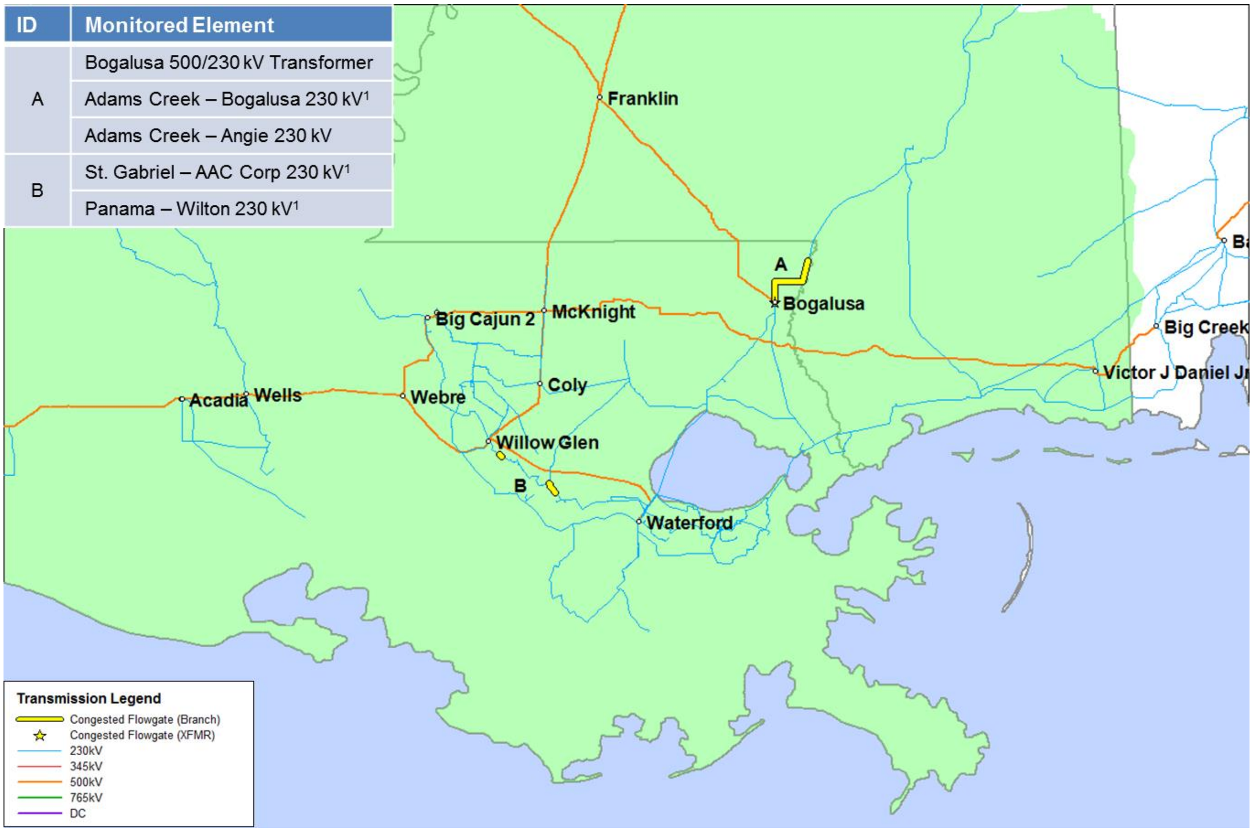


Figure 5.3-3: Amite South/DSG top congested flowgates

WOTAB and Western

The WOTAB and Western load pockets in MISO South have historically seen significant amounts of congestion due to import limitations. The import limitations in both the WOTAB and Western regions require the VLR commitments of units within these load pockets at specific limits in order to maintain system reliability. In order to replicate these VLR commitments, MISO utilizes select N-1, G-1 conditions as part of the economic analysis.

The 2017 MCPS study for the South region identified that the majority of the congestion in this focus area is on the 230 kV lines within the WOTAB load pocket near the Sabine area (Figure 5.3-4). In the event that one of the import lines, most notably the 500 and 230 kV lines, into the Sabine area is out of service

[27] These flowgates include multiple element contingencies (e.g. generator + transmission line events)
[28] These flowgates include single and multiple element contingencies (e.g. generator + transmission line events)

and a generator is lost at the Sabine substation, flows shift to the remaining 230 kV network in the Sabine area.

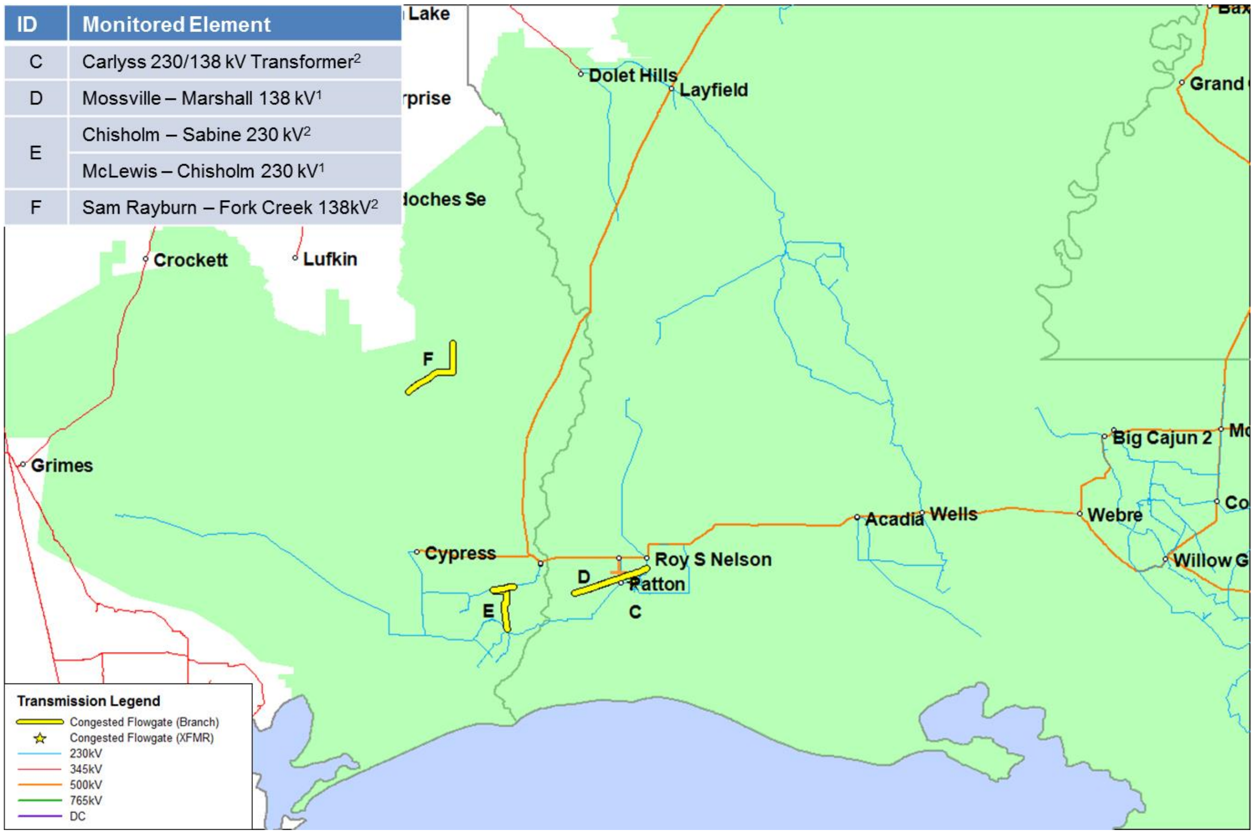


Figure 5.3-4: WOTAB/Western top congested flowgates

Twenty-nine projects were submitted to address congestion in the WOTAB and Western load pockets. These projects were designed to alleviate internal congestion within the load pockets. After the completion of screening, seven of the projects produced adequate benefits to pass the screening criteria.

1. Hartburg – Sabine 500 kV project with a 500/230 kV transformer
2. Hartburg – Orange 500 kV project with a 500/138 kV transformer
3. Hartburg – Sabine 500 kV project with two 500/230 kV transformers and 500/138 kV transformer
4. Patton – Sabine 500 kV project with a 500/230 kV transformer
5. Upgrade Sam Rayburn – Doucette 138 kV transmission line
6. Increase Carlyss 230/138 kV transformer rating to 300 MVA
7. New 500/138 kV transformer at Nelson

These seven projects were then evaluated under the full present value analysis. Of these seven projects, the 500/138 kV transformer at Nelson did not pass the present value analysis with a weighted benefit-to-

[29] These flowgates include multiple element contingencies (e.g. generator + transmission line events)
[30] These flowgates include single and multiple element contingencies (e.g. generator + transmission line events)

cost ratio of 0.62. The remaining six projects were selected as project candidates to undergo further robustness analysis so that the best fit candidates could be identified.

Contingency analysis was performed with each of the six project candidates to identify any potential new flowgates that may be driven by the project. Planning level cost estimates were also developed for each of the project candidates to provide a level basis of comparison.

WOTAB and Western – Sabine Area Projects

Project Candidates 1, 2, 3 and 4 were all designed to alleviate congestion within the Sabine area. Based on the scope of these project candidates, the in-service year has been estimated to be 2023 which is used in the benefit calculations. Of the four project candidates, Project Candidate 1 outperformed the other projects in each of the generating scenarios; therefore it was selected as the best-fit project candidate to alleviate the congestion in the Sabine area.

After selecting Project Candidate 1 as the most effective project to address Sabine area transmission congestion, a scoping level cost estimate was developed in support of the candidate MEP. As part of the scoping level cost estimate process, the project's design was further evaluated. As a result, MISO staff identified two potential alternatives to Project Candidate 1 that provide a new link between the Hartburg and Sabine substations through slightly different configurations which are described in (Table 5.3-8).

	Description of Project Candidate 1 Alternatives	Meets MEP voltage and cost criteria?
Alternative 1 (Original Design)	• New Hartburg – Sabine 500 kV transmission line • New Sabine 500/230 kV transformer • Expand Hartburg and Sabine substations	Yes
Alternative 2	• Tap the existing Sabine – McFadden and Sabine – Nederland 230 kV transmission lines into a new substation • New Hartburg – New substation 500 kV transmission line • New substation 500/230 kV transformer	Yes
Alternative 3	• New Hartburg – Sabine 230 kV transmission line • New Hartburg 500/230 kV transformer • Expand Hartburg and Sabine 230 kV substations	No

Table 5.3-8: Project Candidate 1 Alternative Configurations

Each of the project candidate alternatives went through the same economic, reliability no-harm, and scoping level cost estimation that the original, alternative 1 was subject two. As a result of this analysis, Project Candidate 1 – Alternative 2 has been identified as the best overall solution. A summary of the economic results for each of the project candidates is provided in (Table 5.3-9).

Alternative	Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
		EF	PR	AAT	Weighted		
1	1	0.95	0.88	2.50	1.23	$203	25%
	2	13.94	13.63	9.76	12.98	$2,141	74%
	3	2.81	1.71	1.08	2.03	$334	44%
2	1	1.01	1.01	2.72	1.35	$214	23%
	2	14.69	14.36	10.20	13.66	$2,162	74%
	3	2.97	1.87	1.08	2.15	$341	43%
3	1	1.08	0.97	2.68	1.36	$165	28%
	2	17.14	16.22	11.43	15.63	$1,898	74%
	3	3.28	1.66	1.00	2.18	$265	44%

Table 5.3-9: Project Candidate 1 Alternative Results with full CCGT outage for VLR commitments

Table 5.3-10 shows each of the Project Candidate 1 Alternative results with partial CCGT outages utilized for VLR commitments.

Alternative	Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
		EF	PR	AAT	Weighted		
1	1	0.95	0.96	2.1	1.18	$195	25%
	3	1.3	0.84	0.73	1	$166	36%
2	1	1.01	1.1	2.19	1.28	$202	24%
	3	1.36	0.94	0.77	1.07	$170	35%
3	1	1.08	1.08	2.14	1.29	$157	27%
	3	1.49	1.01	0.85	1.17	$142	34%

Table 5.3-10: Project Candidate 1 Alternative Results with full CCGT outage for VLR commitments

In addition to providing benefits in excess of 1.25 times the cost under each generation scenario evaluated, Alternative 2 has shown the highest level of 20 year Present Value benefit when compared to the other two alternatives. In addition to APC benefits, Alternative 2 fully relieves the congestion in the Sabine/Port Arthur area and provides greater VLR make-whole payment relief when compared to Alternative 3. Project Candidate 1 – Alternative 2 will be further referred to as the Hartburg – Sabine Junction 500 kV Economic Project.

In the additional scenarios, the Hartburg – Sabine Junction 500 kV Economic Project continued to perform well. Additionally, Hartburg – Sabine Junction 500 kV Economic Project underwent the reliability analysis described earlier in this section. The short circuit analysis identified a single over-dutied breaker that will be required to be replaced. Based on the strong performance of the Hartburg – Sabine Junction 500 kV Economic Project under all analysis performed, this project is recommended to the MISO Board of Directors for approval as a Market Efficiency Project.

As a project that meets all of the criteria to be considered a Market Efficiency Project, the MISO BPM-029: Minimum Project Requirements for Competitive Transmission Projects ensures the project is in compliance. A review of the transmission line rating determined that the BPM default minimum line rating of 3000 A was sufficient to achieve all project benefits. Some further analysis was performed that determined that the transformer impedance should be at least 7 percent with a three-phase rating of at least 1,200 MVA. On the low side of the transformer, the breaker symmetrical interruption rating requirement was determined to be 63 kA. Based on these requirements, a scoping level cost estimate for the Hartburg – Sabine Junction 500 kV Economic Project is $129.7 million. This cost estimate includes the breaker replacement identified in the reliability analysis.

WOTAB and Western – Other Area Projects

Project Candidate 5 increases the transmission line rating of Sam Rayburn – Fork Creek – Doucette 138 kV to 137 MVA. This project was shown to address all of the congestion along this transmission line path and performed very well under all scenarios. The planning level cost was estimated to be $2.8 million. Given the scope of this project, the in-service year is estimated at 2020, which is used in the benefit calculations.

At the request of a stakeholder that provided supporting documentation, MISO studied additional sensitivities that considered the ability for future sited RRF Combined Cycle Gas Turbine units subject to VLR commitments to operate in a simple cycle mode. In these additional sensitivities, the Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade project continued to perform well. Additionally, the Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade underwent the reliability analysis described earlier in this section. The project performed very well in the steady state, voltage stability and transient stability analysis where no adverse impacts to the system were identified.

Based on the strong performance of the Sam Rayburn – Fork Creek – Doucette 138 kV Network Upgrade Project under all analysis performed, this project is recommended to the MISO Board of Directors for approval as an Other economic project. Table 5.3-11 shows the Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade project results with full CCGT outage for VLR commitments.

Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
	EF	PR	AAT	Weighted		
1	1.13	10.85	23.04	9.40	$36	23%
2	1.24	9.67	7.97	5.96	$23	68%
3	8.15	23.02	30.55	18.58	$71	27%

Table 5.3-11: Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade project results with full CCGT outage for VLR commitments

Table 5.3-12 shows the Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade project results with partial CCGT outage for VLR commitments.

Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
	EF	PR	AAT	Weighted		
1	1.13	10.89	16.97	8.20	$31	21%
3	1.19	6.33	23.36	7.68	$29	8%

Table 5.3-12: Sam Rayburn – Fork Creek – Doucette 138 kV network upgrade project results with partial CCGT outage for VLR commitments

Project Candidate 6 increases the 230/138 kV transformer rating at the Carlyss substation to 300 MVA. This project was shown to address the congestion on this transformer under all scenarios. The planning level cost was estimated to be $500,000. Given the scope of this project, the in-service year is estimated at 2020, which is used in the benefit calculations.

At the request of a stakeholder that provided supporting documentation, MISO studied additional sensitivities that considered the ability for future sited RRF Combined Cycle Gas Turbine (CCGT) units subject to VLR commitments to operate in a simple cycle mode. In these additional sensitivities, the Substation Equipment Upgrade at Carlyss Project continued to perform well. Additionally, the Substation Equipment Upgrade at Carlyss project underwent the reliability analysis described earlier in this section. The project performed very well in the steady state, voltage stability and transient stability analysis where no adverse impacts to the system were identified.

Based on the strong performance of the Substation Equipment Upgrade at Carlyss under all analysis performed, this project is recommended to the MISO Board of Directors for approval as an Other economic project. Table 5.3-13 shows substation equipment upgrade at Carlyss Project results with full CCGT outage for VLR commitments.

Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
	EF	PR	AAT	Weighted		
1 (Base)	18.24	(2.58)	124.78	31.22	$20	40%
2	2.48	251.10	295.61	160.55	$105	97%
3	48.98	63.55	67.95	58.60	$38	86%

Table 5.3-13: Substation equipment upgrade at Carlyss Project results with full CCGT outage for VLR commitments

Table 5.3-14 shows substation equipment upgrade at Carlyss Project results with partial CCGT outage for VLR commitments.

Generation Scenario	Benefit to Cost Ratios				20-yr Present Value Benefit ($M)	Emergency Energy Contribution to Project Benefits (%)
	EF	PR	AAT	Weighted		
1 (Base)	18.24	(0.65)	(6.46)	5.74	$4	83%
3	2.05	3.89	2.61	2.90	$2	45%

Table 5.3-14: Substation equipment upgrade at Carlyss Project results with partial CCGT outage for VLR commitments

Remainder of LRZ9 (Rest of Louisiana)

The identified congestion in the Remainder of LRZ9 (Rest of Louisiana) was concentrated on the 115 kV network along the Northeastern border between Louisiana and Mississippi (Figure 5.3-5). The congestion was influenced by the assumed future retirements and replacement generation at the Sterlington and Baxter Wilson substations in addition to high west (Perryville) to east (Baxter Wilson) transfers under contingent conditions.

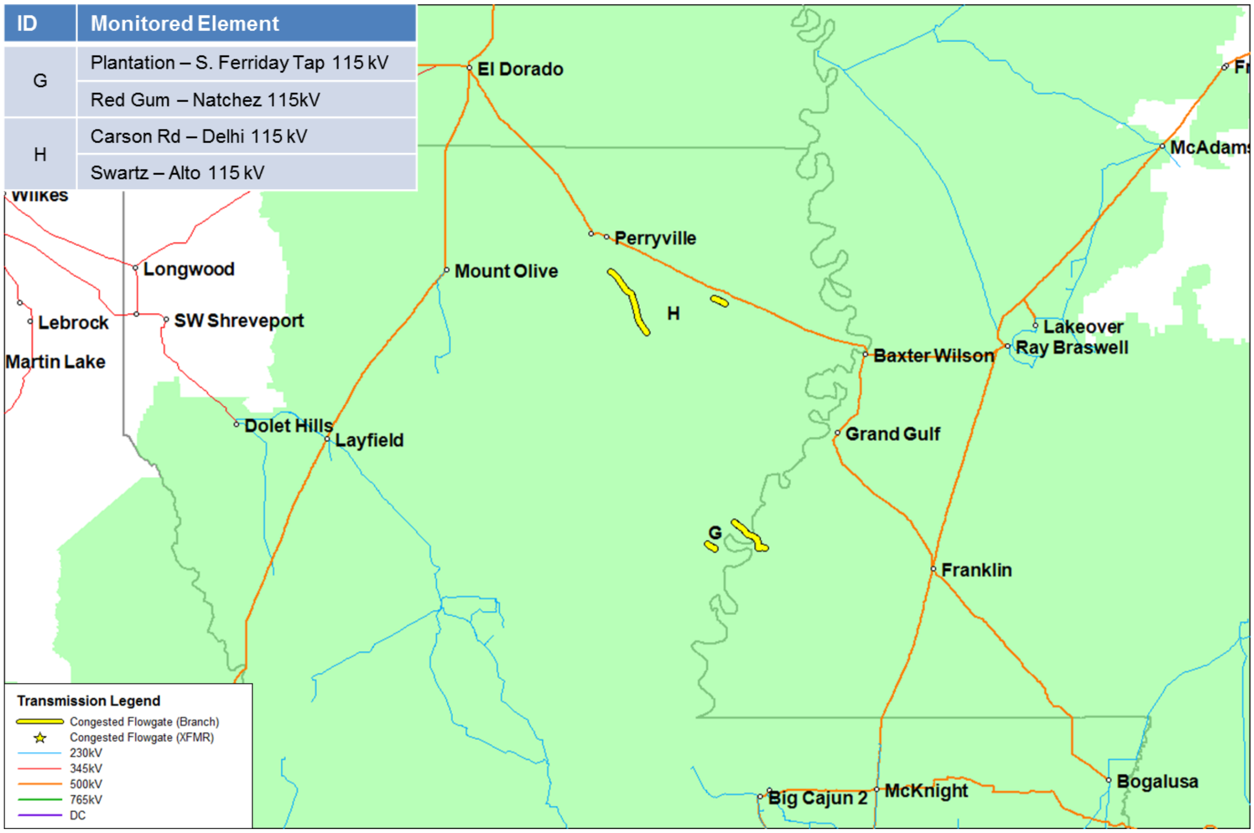


Figure 5.3-5: Remainder of LRZ9 (Rest of Louisiana) top congested flowgates

Five projects were submitted to address the congestion in the Remainder of LRZ9 (Rest of Louisiana). Several of the projects were proposals to build a new 500 kV line across this area to help reduce the transfers on the lower-voltage system, while one of the projects proposed a new link on the 115 kV network to improve the system performance under contingency. After the completion of screening and refinement, none of the projects produced adequate benefits to pass the screening criteria. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

LRZ10 (Mississippi)

The only identified congestion in LRZ10 is on the Greenwood Tap – Greenwood 115 kV transmission line near the MISO/TVA border for the loss of the Choctaw – Clay 500 kV transmission line (Figure 5.3-6). The amount of congestion between each of the MTEP futures varies depending on the amount of generation being retired or replaced in Mississippi.

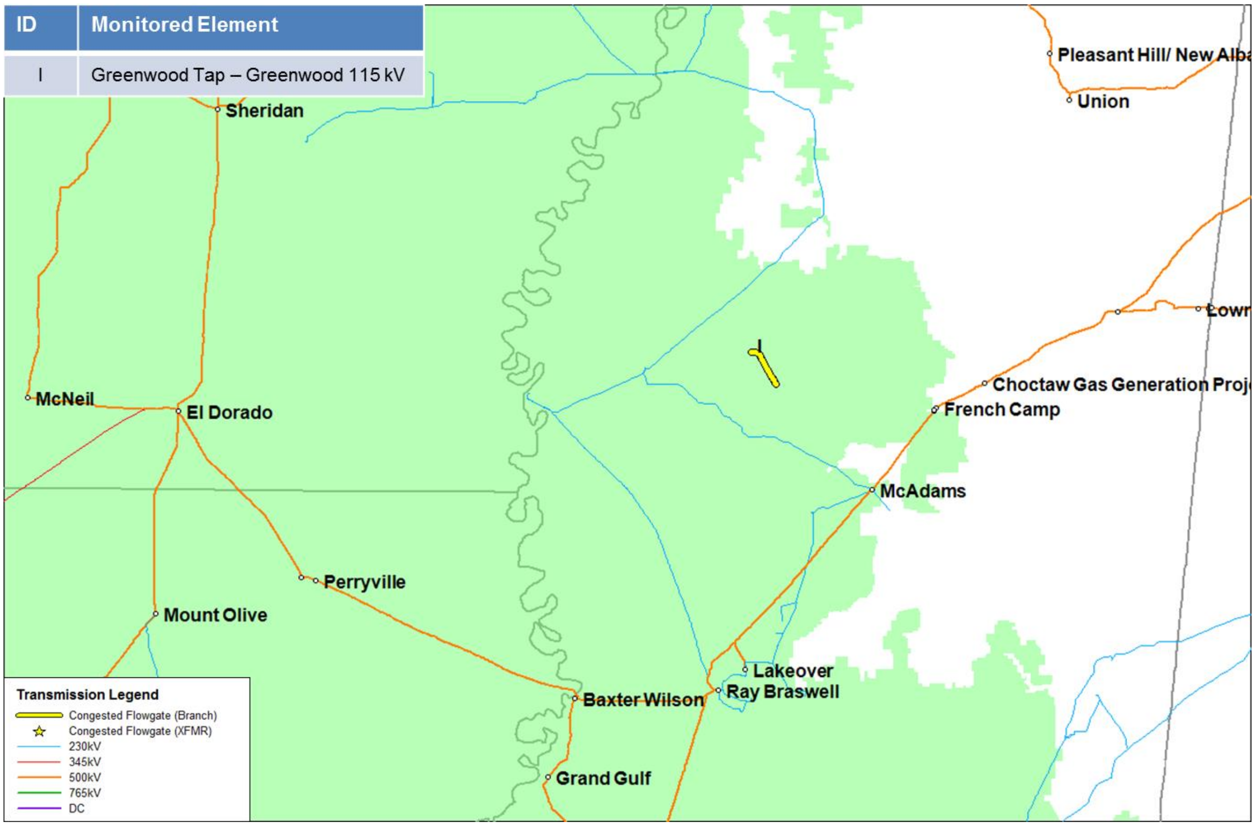


Figure 5.3-6: LRZ10 (Mississippi) top congested flowgates

MTEP reliability project 7906, Upgrade Greenwood – Greenwood Substation to 239 MVA, was submitted for consideration to Appendix A in MTEP17 and is expected to be approved as a reliability project this year. This project was found to completely eliminate the congestion on the Greenwood Tap – Greenwood flowgate; therefore, there was no need to further evaluate projects for LRZ10.

LRZ8 (Arkansas)

The identified congestion in LRZ8 was spread across the footprint with the majority of congestion showing on the Morrilton East to Gleason 161 kV line in central Arkansas (Figure 5.3-7).

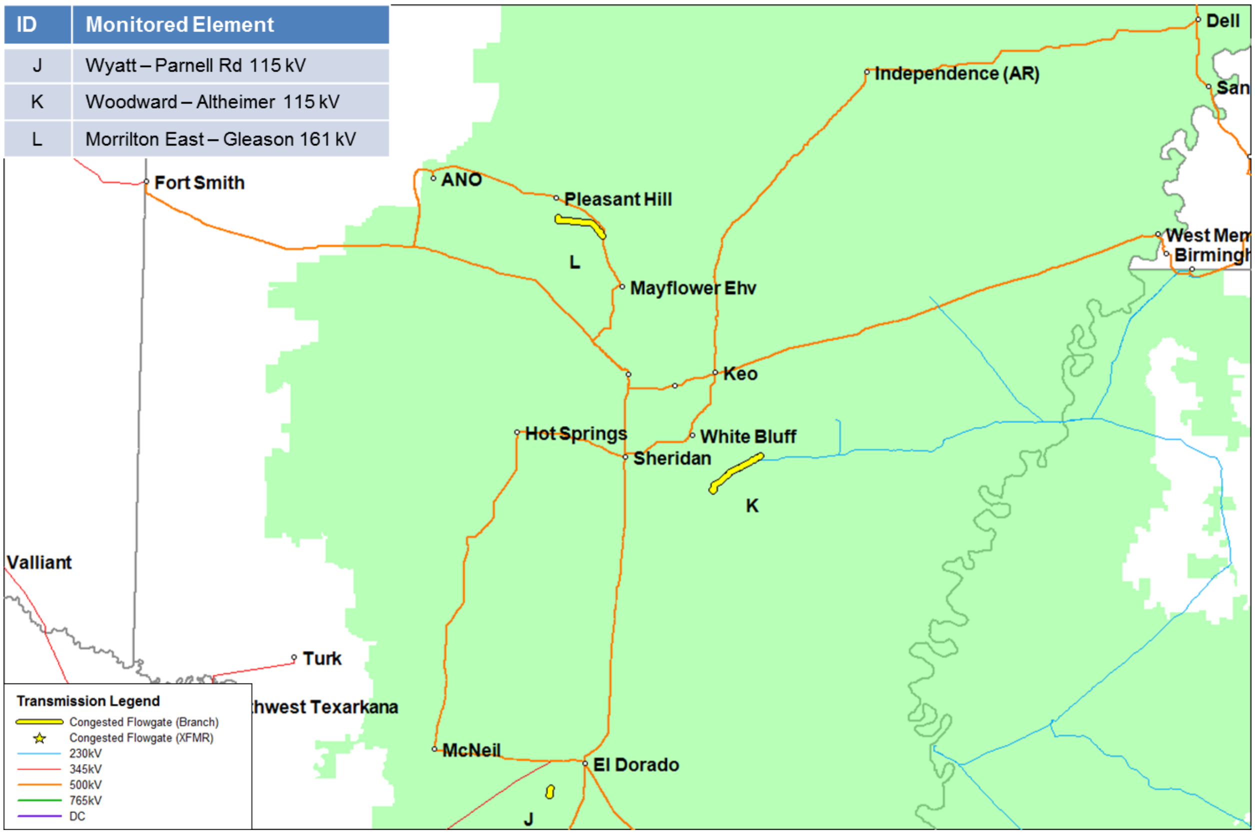


Figure 5.3-7: LRZ8 (Arkansas) top congested flowgates

A total of nine projects were submitted to address the congestion in LRZ8. After the completion of screening and refinement, two projects were selected for further evaluation. Several of the projects proposed tapping one of the area 500 kV lines and adding a new 500/161 kV transformer into the area while others suggested creating a secondary 500 or 345 kV path to support high west-to-east transfers. After the completion of screening and refinement, none of the projects produced adequate benefits to pass the screening criteria. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

5.4 Footprint Diversity Study

Purpose of Study

MISO currently has contractual rights to transfer 1,000 MW of flow between the MISO North/Central and South regions via transmission facilities currently operated by MISO. The primary purpose of this study was to identify potential mitigation plans to increase the interface capability between North/Central and South regions and establish the economic drivers for these plans. MISO utilized the Adjusted Production Cost (APC) metric to evaluate the cost effectiveness for any potential network upgrades under a variety of future sensitivity scenarios. Reduction in settlement cost savings as a benefit was also explored and a stakeholder vetted methodology to capture this benefit was created.

Of the 35 transmission projects that were studied within the Footprint Diversity Study (FDS), none passed the benefit to cost ratio of 1.25 that is used within the Market Congestion Planning study (MCPS) process. The minimal congestion around the physical interface between MISO North/Central and MISO South reduced the potential benefits that can be captured from a transmission project that connects the two regions.

MISO's expanded footprint post integration of the South region and the economic inefficiencies driven by the Operational Reliability Coordination Agreement (ORCA) resulted in the settlement payment associated with the North to South contract path. Based on the settlement agreement between MISO and SPP, MISO implemented a market constraint between its North/Central and South regions to limit transfers to 3,000 MW North to South and 2,500 MW South to North effective January 29, 2014. However, at times the actual market flow capability in the MISO system could be greater than the proposed limits in the settlement agreement.

The annual cost to maintain the settlement constraint is estimated to be up to $38 million and is dependent on the capacity factor usage of the interface. Furthermore, the settlement agreement will expire after five years with the ability to extend at 12-month increments.

Study Summary

MISO Models Utilized

The FDS utilized the same models as the MCPS (Chapter 5.3). The production cost models utilized for the FDS are based on data from PROMOD Powerbase and the corresponding MTEP powerflow cases. The data is refreshed with the most current information and with the system variables (fuel cost, demand, etc.) reflecting the MTEP futures definitions. The agreed-upon future scenarios and weightings for the MTEP17 FDS study are:

- Existing Fleet (EF): 31 percent
- Policy Regulation (PR): 43 percent
- Accelerated Alternative Technologies (AAT): 26 percent

Unlike the MCPS process, the FDS was not focused on addressing top-congested flowgates on the MISO system but was targeting an economic project that connected MISO North/Central and MISO South and therefore increasing the contract path capacity between the two regions.

The three future models had limited physical congestion around the interface. Flows between the two regions are limited primarily from contractual limits. The future regional renewable distribution was the largest driver in flows between the regions. The flow from the three futures was predominantly from MISO North/Central to MISO South (Table 5.4-1)

Year	Future	% Flow Direction N-S	% Flow Direction S-N
2021	AAT	92%	8%
	EF	42%	58%
	PR	72%	28%
2026	AAT	86%	14%
	EF	52%	48%
	PR	76%	24%
2031	AAT	86%	14%
	EF	49%	51%
	PR	83%	17%

Table 5.4-1: Base Model flows between MISO North/Central and MISO South

Table 5.4-1 captures the regional flows in the base model, which uses the Regional Directional Transfer Limit (RDTL) for the limit between the two regions. The RDTL imposes a 3,000 MW limit on North to South flow and 2,500 MW limit on South to North flow. A sensitivity study was run on the base models by removing these RDTL limits and observing the reaction of the model to a non-contractually constrained interface (i.e. no changes were made to physical limits). By relieving the RDTL limits we see minimal hours where flow goes above the current RDTL limits (Table 5.4-2).

	2021			2026			2031		
	EF	PR	AAT	EF	PR	AAT	EF	PR	AAT
Hours Above Contract Path Capacity (%)	49%	52%	78%	43%	57%	69%	47%	65%	67%
Hours Above RDTL (%)	5%	6%	21%	3%	11%	13%	5%	12%	16%

Table 5.4-2: PROMOD Flow Duration with unconstrained MISO North-South Interface

Scenario Analysis

In order to evaluate the economic benefits of transmission projects the study used two scenarios to capture changes in the contractual limits between the two regions.

- Scenario 1: Regional Directional Transfer Limits used as base case
- Scenario 2: Contract Path Capacity of 1,000 MW used as base case

In both scenarios the traditional APC benefit of a transmission project can be measured. Savings in settlement costs can only be measured in Scenario 1 because settlement cost savings are calculated based on the flows above the contract patch capacity up to the RDTLs.

The contract path capacity, as well as the RDTL, were adjusted depending on the transmission project solution. For example if a solution included a new line connecting the two regions with a 1,000 MW line rating, the contract path capacity would be adjusted but no change would be made to the RDTL.

Screening Results

MISO screened a total of 35 project submissions within the FDS using scenarios 1 and 2 described above. The screening used a threshold of 0.8 benefit-to-cost ratio, similar to the MCPS process. The screening results did not have a project that passed the screening threshold in both scenarios. This screening only included the savings in Adjusted Production Cost. Results (Table 5.4-3).

Proj ID	Transmission Solution	Stakeholder Submitted Cost (2017-$M)	Incremental Impact to Contract Path	Scenario 1 Screening Index				Scenario 2 Screening Index			
				AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
1	New 500kV line Rush Island - Jonesboro	970.0	4,173	0.07	0.03	0.04	**0.05**	0.39	0.11	0.15	**0.20**
2	New 765kV line Sullivan to West Mount Vernon New 765/345 kV transformer at West Mount Vernon New 765kV line West Mount Vernon to Joppa New 765/345kV transformer at Joppa New 765kV line Joppa to Dell New 765/500kV transformer at Dell New 500kV line Dell to West Memphis New 500kV line Keo to Sterlington New 500kV line Sterlington to Cocodrie New 500/230kV transformer at Cocodrie New 500kV line Cocodrie to Richard New 500kV line Cocodrie to Big Cajun	3,309.0	4,055	0.10	0.05	0.02	**0.05**	0.18	0.07	0.05	**0.09**
3	New 500kV line St. Francois to Independence Two new 500/345kV transformers at St. Francois	568.0	2,800	0.08	0.01	0.08	**0.06**	0.69	0.17	0.30	**0.36**
4	New 500kV line Beans to Keo Two New 500/345kV transformers at Keo	788.0	2,800	0.16	0.04	0.10	**0.10**	0.61	0.15	0.26	**0.32**
5	New 500kV line Beans to Independence Two new 500/345kV transformers at Independence	582.0	2,800	0.14	0.05	0.09	**0.09**	0.74	0.20	0.30	**0.38**
6	New 500kV line East Joppa to Dell Two new 500/345kV transformers at Dell	450.0	2,800	0.12	0.06	0.02	**0.06**	0.89	0.26	0.30	**0.44**
7	New 345kV line Dell to St. Francis New 345kV line St. Francis to Lutesville New 345/500kV transformer at Dell	519.2	2,734	0.12	0.04	(0.01)	**0.04**	0.79	0.21	0.23	**0.37**
8	New 500kV line Independence to Fletcher New 500/345kV Transformer at Fletcher New 500kV line Fletcher to St. Francois New 500kV transformer at St. Francois	597.3	2,140	0.06	0.01	0.05	**0.04**	0.62	0.16	0.25	**0.32**
9	New 500kV line Dell to Shawnee New 500kV line Shawnee to Baldwin Two new 500/345kV transformers at Baldwin	656.7	2,140	0.06	0.06	0.09	**0.07**	0.57	0.19	0.27	**0.32**
10	New 500kV line Fletcher to Independence New 500kV line Fletcher to Labadie Two new 500/345kV transformers at Labadie Two new 500/345kV transformers at Fletcher	679.8	2,140	0.04	0.02	0.07	**0.05**	0.53	0.14	0.24	**0.29**
11	New 500kV line Dell to West New Madrid New 500kV line West New Madrid to Lutesville Two new 500/345kV transformers at Lutesville	357.6	2,088	0.02	0.03	0.01	**0.02**	1.00	0.27	0.35	**0.50**
12	New 345kV line Powerln-Rd to Gobbler Knob New 345kV line Gobbler Knob to Lutesville New 345kV line Fletcher to St. Francois	501.0	1,793	0.09	0.02	0.02	**0.04**	0.60	0.17	0.25	**0.32**
13	New 500kV line Sans Souci to Prairie State New 500/345kV transformer at Prairie State	320.0	1,548	0.09	0.03	0.07	**0.06**	0.99	0.29	0.45	**0.54**
14	New 345kV line Independence to Fletcher New 345kV line Fletcher to St. Francois Two new 500/345kV transformers at Independence	408.6	1,330	0.01	0.04	0.07	**0.05**	0.63	0.19	0.29	**0.35**
15	New 345kV line Fletcher to Indepence New 345kV line Fletcher to Labadie Two new 500/345kV transformers at Independence	468.3	1,330	0.06	0.03	(0.01)	**0.02**	0.58	0.16	0.23	**0.30**
16	New 161kV line Jim Hill to Berntie	55.0	558	(0.37)	0.11	0.06	**(0.03)**	2.15	0.85	0.96	**1.24**
17	New 161kV line Bernie to St. Francois New 161kV line Bernie to New Richland New 161kV line Bernie to Jim Hill	100.0	363	(0.11)	0.04	0.13	**0.04**	0.93	0.34	0.30	**0.48**
18	New 345kV line Joppa to Baldwin	187.6	-	0.15	0.10	0.18	**0.15**	0.11	0.01	(0.02)	**0.02**
19	New 354kV line Wilson to Paradise New 500/345kV transformer at Paradise	54.1	-	0.32	0.81	0.59	**0.59**	0.31	0.24	0.47	**0.36**
20	New 500kV line Wilson to Paradise New 500/345kV transformer at Wilson	84.0	-	0.30	0.58	0.26	**0.37**	0.17	0.39	0.25	**0.28**
21	New 345kV line W. New Madrid to Baldwin	250.6	-	(0.02)	0.01	0.08	**0.03**	0.08	0.02	(0.01)	**0.02**

22	New 500kV line W. New Madrid to Baldwin Two new 500/345kV transformers at Baldwin	389.1	-	(0.00)	0.05	0.09	**0.05**	(0.02)	0.02	0.03	**0.01**
23	New 345kV line W. New Madrid to Joppa	134.5	-	0.14	0.12	0.09	**0.11**	0.14	0.00	(0.02)	**0.03**
24	New 500kV line W. New Madrid to Joppa Two new 500/345kV transformers at Joppa	244.8	-	(0.01)	0.04	0.09	**0.05**	0.09	0.03	(0.04)	**0.02**
25	New 345kV line W. New Madrid to Joppa New 345kV line Joppa to Baldwin	322.1	-	0.10	(0.01)	0.07	**0.05**	0.11	0.04	(0.01)	**0.04**
26	New 500kV line W. New Madrid to Joppa Two new 500/345kV transformers at Joppa New 500kV line Baldwin to Joppa Two new 500/345kV transformers at Baldwin	528.1	-	0.05	0.06	0.06	**0.06**	0.06	0.03	0.03	**0.03**
27	New 500kV line W. New Madrid to Shawnee	193.1	-	0.24	0.06	0.11	**0.13**	0.18	0.08	0.01	**0.07**
28	New 500kV line W. New Madrid to Shawnee New 500kV line Shawnee to Baldwin Two new 500/345kV transformers at Baldwin	519.2	-	0.09	0.06	0.11	**0.09**	0.10	0.04	0.10	**0.08**
29	New 345kV line Fletcher to St. Francois	103.2	-	0.02	0.11	0.03	**0.05**	0.22	0.03	(0.05)	**0.04**
30	New 345kV line Fletcher to Independence Two new 500/345kV transformers at Independence	304.7	-	0.09	0.04	0.03	**0.05**	0.11	0.04	0.06	**0.07**
31	New 500kV line Fletcher to Independence Two new 500/345kV transformers at Fletcher	411.0	-	0.08	0.04	0.05	**0.06**	0.13	0.01	0.07	**0.07**
32	New 500kV line Dell to West New Madrid New 500kV line Dell to Independence New 500kV line tapping Dell - Independence to Jonesboro Two new 500/161kV transformers at Jonesboro	461.0	-	(0.01)	0.03	0.04	**0.03**	(0.06)	(0.08)	(0.04)	**(0.05)**
33	New 345 kV line Lutesville to Jim Hill New 345/161kV transformer at Jim Hill	146.0	800	(0.10)	0.03	(0.04)	**(0.03)**	1.40	0.51	0.60	**0.78**
34	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill New 161 kV line from Jim Hill to Dell	237.0	1,300	(0.01)	0.02	0.00	**0.01**	1.15	0.36	0.49	**0.62**
35	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill Two New 161 kV lines from Jim Hill to Dell	276.0	1,900	0.08	0.00	0.02	**(0.01)**	1.32	0.41	0.48	**0.68**

Table 5.4-3: 2031 Screening Index for Solution Ideas

Settlement Cost Calculation

In addition to calculating APC benefits, select projects settlement cost savings were calculated. The JOA settlement agreement has three distinct compensation phases. Phase I covers the period of January 29, 2014 through January 31, 2016. Phase II covers the period from February 1, 2016 through January 31, 2017. Phase III covers all years after the January 31, 2017, Phase II date. Per these dates any PROMOD model using future planning years will utilize the Phase III compensation for each a11nnual Available System Capacity (ASC) Usage Capacity Factor (Table 5.4-4).

Annual ASC Usage Capacity Factor	Monthly Payment [$M]	Annual Payment [$M]	Escalation Rate starting February 1, 2020
< 20%	$1.33	$16	2%
20% - 70% (inclusive)	$2.25	$27	2%
> 70%	$3.17	$38	4%

Table 5.4-4: Payment structure

Compensation Adjustment for changes in Contract Path Capacity

For every megawatt of increased contract path capacity the monthly payment will be reduced by $667 /MW-month ($8,004/MW-year.) For every megawatt of decreased contract path capacity the monthly payment will be increased by $667/MW-month ($8,004 /MW-year.)

Compensation Adjustment for changes in Regional Directional Transfer Limit

For every megawatt of increased Regional Directional Transfer Limit the monthly payment will be increased by $667/MW-month ($8,004/MW-year.) For every megawatt of decreased contract path capacity the monthly payment will be decreased by $667/MW-month ($8,004/MW-year.)

Proposed Transmission Projects Impact on Compensation Calculation

A transmission project that connects MISO South with MISO North using MISO-owned transmission facilities will potentially impact both the Contract Path Capacity as well as the Regional Directional Limit. Two examples indicate the impact on both the Contract Path Capacity as well as the RDTL (Table 5.4-5).

	Example A	Example B
Project line rating [MW]	1,000	2,500
Contract Path Capacity [MW]	1,000 + 1,000 = 2,000	1,000 + 2,500 = 3,500
Regional Directional Transfer Limit [MW]	No Change	3,500

Table 5.4-5: Example Contract Path Capacity

Since a project will impact both the flows and economics in the system as well as adjusting the settlement compensation calculation, a project’s impact on the settlement cost amount may be used as metric when evaluating project benefits. If a proposed transmission project decreases the ASC Usage Capacity Factor and moves the compensation level from a higher payment tier to a lower payment tier, the project provides settlement cost savings.

Present Value Analysis on Select Projects

A select group of solution ideas were evaluated for full present value analysis. Present value analysis was calculated using APC savings for scenarios 1 and 2. Settlement cost savings were then calculated for Scenario 1 and a full present value analysis including both APC savings and settlement cost savings was calculated. Table 5.4-6 shows the APC Present Value Analysis for some select projects and Table 5.4-7: APC and Settlement Cost Saving Present Value Analysis for the same projects.

Proj. ID	Transmission Solution	Stakeholder Submitted Cost (2017-$M)	Incremental Impact to Contract Path	Scenario 1					Scenario 2			
				Benefit to Cost Ratios				20-yr PV Benefit ($M)	Benefit to Cost Ratios			
				AAT	EF	PR	Weighted		AAT	EF	PR	Weighted
16	New 161kV line Jim Hill to Bernie	55.0	558	0.18	(0.02)	(0.01)	**0.03**	**2.2**	2.49	1.09	1.13	**1.47**
33	New 345 kV line Lutesville to Jim Hill New 345/161kV transformer at Jim Hill	146.0	800	0.00	0.02	(0.04)	**(0.01)**	**(2.3)**	1.37	0.50	0.55	**0.75**
34	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill New 161 kV line from Jim Hill to Dell	237.0	1,300	0.01	0.01	(0.04)	**(0.01)**	**(3.7)**	1.16	0.35	0.46	**0.61**
35	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill Two New 161 kV lines from Jim Hill to Dell	276.0	1,900	(0.05)	(0.00)	(0.01)	**(0.02)**	**(6.0)**	1.26	0.41	0.46	**0.65**

Table 5.4-6: APC Present Value Analysis for Select Projects

Proj. ID	Transmission Solution	Stakeholder Submitted Cost (2017-$M)	Incremental Impact to Contract Path	Incremental Impact to RDTL	Scenario 1				
					Benefit to Cost Ratios (APC & Settlement Cost Savings)				20-yr PV Benefit ($M)
					AAT	EF	PR	Weighted	
16	New 161kV line Jim Hill to Bernie	55.0	558	-	0.51	0.72	0.49	**0.57**	**38.2**
33	New 345 kV line Lutesville to Jim Hill New 345/161kV transformer at Jim Hill	146.0	800	-	0.20	0.36	0.38	**0.33**	**58.0**
34	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill New 161 kV line from Jim Hill to Dell	237.0	1,300	-	0.32	0.29	0.35	**0.32**	**94.0**
35	New 345 kV line Lutesville to Jim Hill Two New 345/161kV transformers at Jim Hill Two New 161 kV lines from Jim Hill to Dell	276.0	1,900	400*	0.37	0.32	0.41	**0.37**	**124.3**

Table 4.4-7: APC and Settlement Cost Saving Present Value Analysis for Select Projects

Based on the screening and full present value analysis MISO did not find a project that provided robust benefit-to-cost benefits that exceeded 1.25 percent. While there are significant potential savings in settlement costs due to increased contract path capacity, the minimal amount of physical congestion on the interface between MISO North/Central and MISO South within MTEP models did not provide enough economic benefit to justify a project candidate for board approval. The additional insight into flows between the regions as well as the physical constraints proved to be valuable for both MISO as well as stakeholders. Additionally the stakeholder-vetted methodology of calculating settlement costs, as well the corresponding settlement cost savings due to a transmission project between the two regions, will potentially be able to be utilized in other MISO studies.