MTEP17

MISO TRANSMISSION EXPANSION PLAN

MTEP17 REPORT

October 2017

Table of Contents

Executive Summary

Introduction

MISO System Planning is focused on ensuring reliable and efficient electric infrastructure to meet future needs.

The Midcontinent Independent System Operator (MISO) annually develops the MISO Transmission Expansion Plan (MTEP) through an inclusive and transparent stakeholder process. MISO evaluates various types of projects through the MTEP process that, when taken together, result in an electric infrastructure plan that is sufficiently robust to meet local and regional reliability needs; enable competition among wholesale capacity and energy suppliers in the MISO markets; and allow for competition among transmission developers in the assignment of certain transmission projects. **MISO's system planning process ensures the reliable and resilient operation of the transmission system; supports achievement of state and federal energy policy requirements; and enables a competitive electricity market to benefit all customers.**

The MISO region is undergoing a significant transformation in its resource portfolio due to a combination of factors including federal and state policies, economics, evolving technologies and consumer preferences. The trends indicate a shift to increased numbers of variable, energy resources and a reduction in traditional base load resources designed to meet energy and capacity needs. As this new model emerges MISO must plan for a transmission system that is fundamentally more flexible to support an increasingly diverse set of resource types.

In MTEP17, consistent with the MISO tariff and the requirements of FERC Order 1000, MISO takes a regional, long-term view of system requirements and seeks to identify transmission solutions that meet those regional needs. Although the exact future resource mix remains uncertain, proactively identifying infrastructure that is valuable under a number of long-term scenarios provides the opportunity for more efficient investment, particularly given the long lead time typically needed to plan, approve and construct regional transmission solutions. These regional analyses, taken together with analysis of near term reliability needs, analysis of transmission needed to support resources joining and leaving the system, and identification of local system needs, collectively comprise the MISO Transmission Expansion Plan and provide a strong foundation to ensure that MISO has a transmission system that meets customer needs now and in the future.

MTEP17 Overview

In MTEP17, MISO staff recommends the MISO Board of Directors approve $2.7 billion of new transmission expansion projects with expected in-service dates through 2024. MTEP17, the 14th edition of this publication, reflects the most recent 18 months of collaborative system planning across a diverse geographic and regulatory landscape covering 900,000 square miles. The projects in MTEP17 bring continued reliability to the electric grid and deliver low-cost energy to customers.

In MTEP17, the 14th edition of this publication, MISO staff recommends $2.7 billion of new transmission expansion projects for Board of Directors' approval.

As the MISO region experiences changes and growth, the MTEP also reflects analysis of specific issues to ensure the region is well-positioned to meet future electricity demand and regulatory mandates. Notable work efforts performed during this planning cycle include:

- Ongoing evaluation of transmission needs and identification of solutions through Market Congestion Planning Studies[1]
- Providing transparency around the Resource Adequacy outlook in the MISO Region[2]
- Greater interregional planning collaboration along MISO's seams[3]
- Seeking improved Generation Interconnection Process outcomes through Queue Reform[4]
- Development of overlays that provide a macro view future Bulk Electric System opportunities and to shed light on future regional transmission issues

MTEP17 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
- **Book 3** presents the policy landscape. It summarizes regional and interregional studies
- **Book 4** presents additional regional energy information
- **Appendices A through F** provide detailed assumptions, results, project information and stakeholder feedback.

MTEP17 Highlights:

- **353 new projects** for inclusion in Appendix A
- **$12.9 billion in projects** constructed in the MISO region since 2003
- Over 5,000MW of generation enabled by new Transmission in MTEP17
- Recommendation to approve five interregional Targeted Market Efficiency projects with PJM
- MISO is recommending the West of the Atchafalaya Basin (WOTAB) 500kV Economic Project as a Market Efficiency Project in MTEP17

[1] See MTEP17 Report, Section 5.3
[2] See Book 2
[3] See Section 8
[4] See Section 4.2

The MISO Planning Approach

In March of 2017 MISO Board of Directors reaffirmed the principles forming the foundation of the organization's planning efforts. These principles were created to improve and guide transmission investment in the region and to give strategic direction to the MISO transmission planning process.

Guiding Principles for Expansion Plans

The system expansion plans produced through the MISO planning process must ensure the reliable operation of the transmission system; support achievement of state and federal energy policy requirements; and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of a sufficiently robust transmission infrastructure to meet local and regional reliability standards as well as enable competition among wholesale capacity and energy suppliers.

In support of these goals, the MISO regional expansion planning process should meet each of the six Guiding Principles.[5]

1. Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system cost
2. Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs
3. Support state and federal energy policy requirements by planning for access to a changing resource mix
4. Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects
5. Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context to inform regarding choices
6. Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations

In support of these guiding principles, MISO implemented a planning process to reflect a view of projects inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons.

A number of condition precedents must be met through this process before approving long-term transmission that will support future changes in the resource mix and accommodate documented energy policies. These conditions support the MISO guiding principles and include:

- Aligned interests regarding the issue(s) for regional transmission solutions to collectively address
- A robust business case for the project(s)
- Clearly defined cost allocation methods that closely align who pays with who benefits over time
- Cost recovery mechanisms that reduce financial risk

[5] The MISO Planning Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, March 2013 and March 2017.

MTEP17 Planning Initiatives

In furtherance of the guiding principles described above MISO was engaged in a number of planning initiatives in the MTEP17 cycle. These initiatives demonstrate the range of MISO's planning process across multiple time horizons.

Regional Transmission Overlay Study

The MISO region is undergoing a significant transformation in its resource portfolio due to a combination of factors including federal and state policies, economics and evolving technologies. If these trends continue, the transmission system may require additional flexibility that can be afforded by expanded transmission infrastructure to enable the transition in a reliable and efficient fashion. The Regional Transmission Overlay Study, as a key component of the MISO regional transmission planning process, is designed to review and to evaluate long-term transmission needs and develop conceptual overlays in positioning the transmission grid for the future. Overlay development is intended to provide a macro view of future Bulk Electric System opportunities and to shed light on future regional transmission issues and potential solutions.

The changing regional landscape and the long lead time needed to plan, approve and construct regional transmission solutions underscore the importance for MISO to take a long-term view of potential system needs periodically, in addition to annual near-term reliability and market congestion planning assessments. Long-term conceptual overlay planning of this type identifies indicative transmission overlays to help guide future system needs in accommodating the continued shift of the resource mix.

The Regional Transmission Overlay Study establishes an integrated planning approach to developing long-term indicative overlays from a regional perspective, considering both reliability needs and economic opportunities. MISO has worked with stakeholders and developed such indicative long-term overlays that could be used to support a variety of future resource mix projections for the three MTEP17 futures.

2017 overlay planning analysis is brought to conclusion with identification of indicative long-term overlays to help guide future transmission issues analysis and potential solution development in support of changing system needs.

Guided by insights gained from the 2017 overlay evaluation and stakeholder inputs, MISO's regional planning focus turns to additional planning analyses to further identify issues underpinning future system needs. Going forward, MISO will continue to evolve its regional planning approach to meet constantly changing reliability, economic and public policy needs, stepping towards an integrated transmission planning approach to identify the most efficient and cost-effective solutions to collectively address a suite of issues.

MTEP Future Scenarios

To plan for a range of reasonably foreseeable future outcomes, MISO studied three future scenarios for MTEP17: Existing Fleet, Policy Regulations and Accelerated Alternative Technologies. Existing Fleet modeled minimal change to the current generation fleet with low natural gas prices and load forecast growth rates as well as age-related retirements for coal, gas and oil thermal units. Policy Regulations modeled the continuation of recent trends with base natural gas prices and load forecast growth rate, additional retirement of coal units prior to the end of their useful life, and a 25 percent reduction in carbon emissions. Accelerated Alternative Technologies modeled a high booked of generation fleet change with high natural gas prices and load forecast growth rate, higher levels of coal retirements reflecting economics and a 35 percent reduction in carbon emissions[6]. These futures will guide annual transmission decisions through the MTEP17 process and be used to develop long-term transmission planning roadmaps for future MTEP cycles.

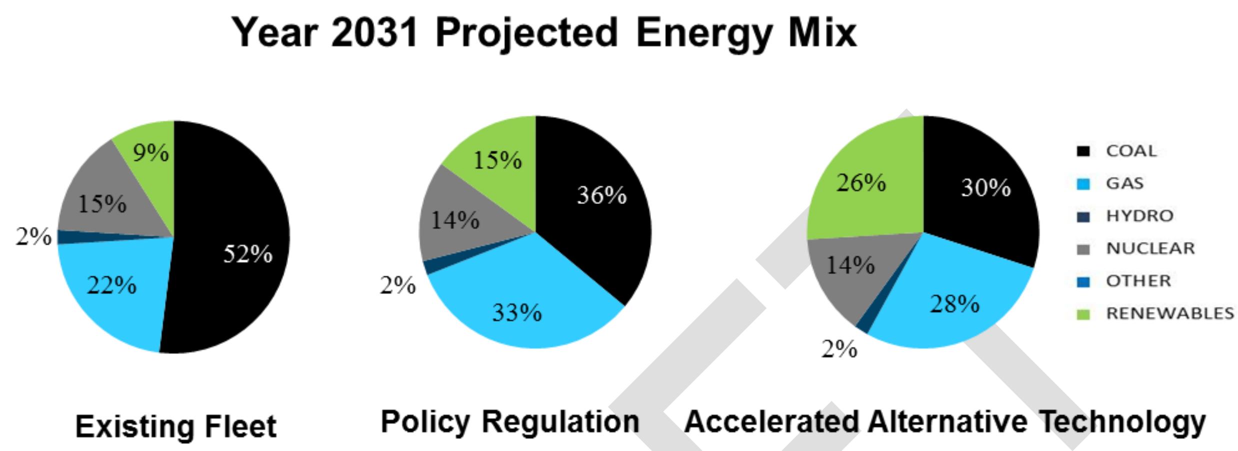


Figure 1.1: Year 2031 Projected Energy Mix

Generation Queue Reform

Another significant aspect of portfolio evolution is the need to interconnect new generation resources in an efficient manner. In January 2017, FERC approved MISO's latest interconnection queue reform efforts to expedite the processing of newer projects and the transition of older queued projects. The new queue process is designed to provide more certainty in schedules and cost for the interconnection customers by having scheduled restudies as part of the process, two dedicated off-ramps for customers to withdraw and reduce their risk, and three separate cash-at-risk milestones to reduce the likelihood of non-ready projects proceeding further in the queue process.

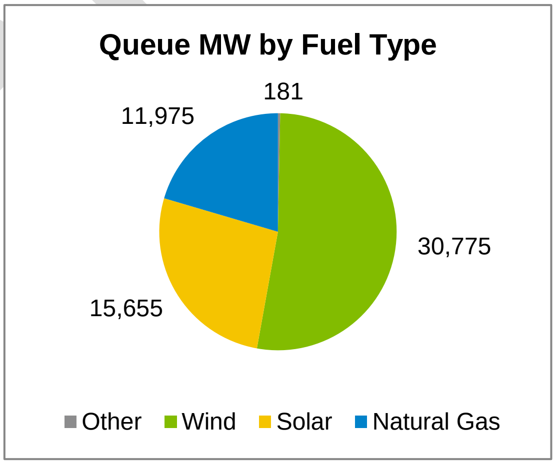


Figure 1.2: Queue MW by Fuel Type

With the addition of the latest Interconnection Requests submitted for the August 2017 Queue Cycle, MISO's Generator Interconnection Queue has grown to more than 350 projects totaling 58 GW. This is an unprecedented amount of requested generation driven by phase-outs of wind production tax credits and investment tax credits for solar, expected coal retirements and state renewable portfolio standards. MISO's West Region[7] alone faces more than 22 GW of generation (Figure 1.2 and Figure 1.3) under study and will require significant transmission to interconnect even a fraction of that level of new resources.

[6] Carbon reductions modeled in MTEP17 are reductions from 2005 levels.
[7] Consisting of the states of Montana, North Dakota, South Dakota, Minnesota, and Iowa

Although the challenges are many, MISO's generator interconnection process identified new transmission, reflected in MTEP17, which will enable over 5,000 MW of new capacity to connect to the MISO system.

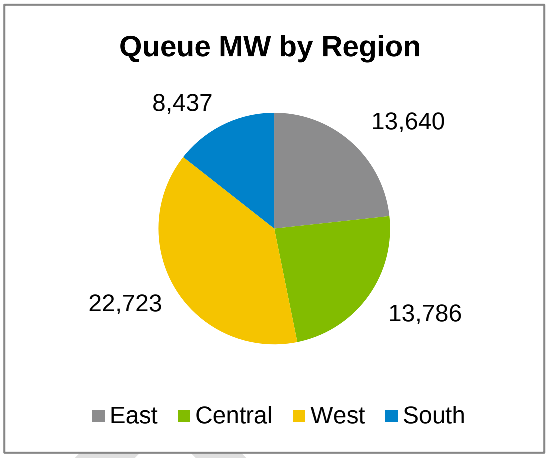


Figure 1.3: Queue MW by Region

Generation Retirements

Generation suspension and retirement activity (Attachment Y) has returned to more typical levels likely due to easing regulatory pressure as asset owners move forward to address economics and age related retirements. Only one Attachment Y notification resulted in a System Support Resource agreement in 2017. The unit (Teche 3 in the MISO South subregion) will remain in service until necessary transmission upgrades are in place.

Throughout 2017, MISO worked to enhance Attachment Y Tariff provisions to address Independent Market Monitor (IMM) recommendation to align the Planning Reserve Auction (PRA) and the Attachment Y process. The proposed Tariff changes include a more streamlined process to facilitate transition from suspension to retirement decisions.

Resource Adequacy

MISO will continue to provide insight around resource adequacy in the region. With small and static reserve margin projections into the future, continued transparency around resource adequacy risks remains important for the MISO footprint. Additional work to refine the calculation of the required reserve margin will ensure the analysis correctly reflects the locations of resources and the operating impacts of a new mix of resource types including reduced levels of baseload coal, increased intermittent resources such as wind, and increased reliance on non-traditional resource types such as demand response and energy storage to the MISO footprint.

Assessments conducted during 2017 via the OMS-MISO survey project that the MISO system will have sufficient levels of reserve capacity in the five year time horizon. Changes in forecasted demand and resource commitments have resulted in 2.7 GW to 4.8 GW of resources in excess of the regional requirement. Achieving this level of resource adequacy will require states and load serving entities to continue the planned actions reflected in the survey results

Reliability Planning

MISO continues to perform annual assessments and identify projects needed to ensure the continued system reliability in compliance with applicable local and regional reliability standards. MTEP17 reliability assessment begins with a roll-up of issues and potential solutions from the local planning processes of the Transmission Owners (TO), followed by an independent reliability assessment conducted by MISO to evaluate and integrate TO local planning information into the development of the overall MISO transmission expansion plan with stakeholder inputs throughout the planning cycle. MISO closely coordinates the annual reliability assessment with other planning efforts, such as Market Congestion Planning studies to ensure the most efficient and cost-effective overall system plan is identified.

As the result of the MTEP17 reliability assessment, 353 reliability projects totaling $2.7 billion are included in MTEP17 Appendix A, accounting for 86% of the total transmission infrastructure investment in MTEP17.

Market Congestion Planning Study-South

The latest MTEP17 Market Congestion Planning Study (MCPS) for South region is built upon the progress made during the previous MTEP cycles occurring after the south region integration. During this study cycle, MISO staff has continued their planning effort for the MISO South region to ascertain whether there are cost-effective alternatives to serve the load, at a lower overall cost, by eliminating congestion and minimizing Voltage and Local Reliability (VLR) resource commitments.

As a result of this process, MISO is recommending the West of the Atchafalaya Basin (WOTAB) 500kV Economic Project as a Market Efficiency Project in MTEP17. The project provides economic benefits in excess of 1.25 times the costs under each generation siting scenario analyzed. The project improves area reliability by providing additional import capability into the WOTAB load pocket, reduces Voltage and Local Reliability (VLR) make whole payments, and provides additional operational flexibility. Historically, this region has experienced generation and transmission outage conditions outside the scope of planning criteria, in some cases leading to maximum generation alerts and conservative operations. The proposed project will provide additional robustness during these conditions in addition to the economic benefits demonstrated. Given the operational history of this area, the aging generation fleet, potential for industrial load growth, and limited import capability into WOTAB load pocket, the project addresses current needs as well as probable future area needs.

Interregional Planning

Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning regions are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed. In MTEP17, several studies were conducted with both PJM and Southwest Power Pool (SPP).

MISO and PJM developed a new interregional project type, Targeted Market Efficiency Projects (TMEP). The goal of TMEPs is to identify high value, low cost projects that reduce persistent, historical Market-to-Market congestion. The TMEP project category, including regional and interregional cost allocation, have been approved by FERC and have been incorporated in the MISO and PJM Joint Operation Agreement (JOA) and respective tariffs.

In 2017 MISO and PJM completed a Targeted Market Efficiency Projects study which identified five projects of this type with benefits of $99.6 million and total cost of only $17.25 million. These five Targeted Market Efficiency Projects have been included for recommendation in MTEP17 Appendix A.

In addition, MISO and PJM are on schedule to complete a two-year Coordinated System Plan Study that evaluated Interregional Market Efficiency Project proposals for potential inclusion in MTEP17 and PJM's expansion plan, RTEP17. One project, the Thayer – Morrison 138 kV new transmission line, continues to look promising as an Interregional Market Efficiency Project. The study and cost allocation for this project are in the process of being finalized.

MISO and SPP, completed their second Coordinated System Plan (CSP) study. The study identified one potential interregional project for further evaluation within each region, whereby MISO's regional analyses determined there existed more cost-effective and efficient regional alternatives. That alternative, a no cost operating guide, is included in the full MTEP17 report. MISO and SPP will be exploring process improvements to allow both RTOs to align more closely how each address future interregional system planning needs stemming from a dramatically changing future energy landscape expected to impact both RTOs.

Competitive Transmission Process

In response to FERC Order 1000 reforms, MISO established a process that opens up opportunities for non-incumbent transmission developers to construct, own, operate, and maintain transmission in the MISO footprint.

Throughout 2017, MISO and stakeholders worked together through the Competitive Transmission Task Team[8] to identify lessons learned from the first implementation of MISO's Competitive Developer Selection Process and to discuss potential process improvements that could be made to the Developer Qualification and Competitive Developer Selection Process. Based on these discussions, MISO filed tariff revisions on October 6 intended to improve the efficiency, transparency, and adaptability of the Competitive Transmission Process and to scale the process to enable MISO to more cost-effectively handle multiple Competitive Transmission Projects in a given year.

MISO will have its second competitive project in MTEP17 with the recommendation of the West of the Atchafalaya Basin (WOTAB) 500kV Economic Project as a Market Efficiency Project.

Looking Forward

Regional Modeling and New Technologies

The plethora of rapidly increasing emerging technologies greatly increases the scope and complexity of transmission planning. Advances in battery storage, solar, wind, high-voltage direct current (HVDC) and flow control devices are changing the bulk electric system and impact the way MISO operates and plans for it. Driven by the shale boom, gas-fired generators are rapidly replacing coal and nuclear generation. MISO will help state regulators and members understand the risks and value created by changes in economic and policy conditions by providing data transparency and offering technical analysis.

The Renewable Integration Impact Assessment which kicked off in 2017 is focused on finding integration inflection points of increasing renewable energy in the MISO system. It will provide technically rigorous, concrete examples of integration issues and examine potential solutions to mitigate them, inform areas of focus and the sequencing of actions required as penetration increases, and facilitate a broader conversation about renewable energy-driven impacts on the reliability of the electric system.

Distributed Energy Resources (DER) and other new technologies are also being evaluated to determine their impact on the type and timing of new transmission facilities. The insights achieved in the Renewable Integration Impact Assessment, Queue reform and resource adequacy are being assessed along with energy efficiency, demand response and distributed energy resources to determine what the transmission system of the future needs to look like to be able to meet the emerging needs of our stakeholders.

MISO will continue to focus on the development of additional skills, modeling tools and supporting processes needed to understand the impacts of these trends. Future studies included in the MTEP will reflect the increased integration of expected gas supply and delivery impacts into transmission planning, and will incorporate the addition of emerging technologies in the resource mix. Going forward, MISO will continue to focus its analysis on impacts of increasing gas-fired generation as it replaces baseload and

[8] https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/CTTT

fast start/ramping resources, increasing renewable penetration, the ability of HVDC to connect weakly connected areas, and emerging alternative technologies such as energy storage and distributed generation.

Cost Allocation Review

The objective of MISO transmission cost allocation methodologies is to align as best as possible who pays with who benefits over time from regional transmission expansion. Currently, MISO is working with stakeholders to evaluate transmission cost allocation methodologies given changing system and regulatory conditions. Some factors that warrant evaluation of cost allocation for future transmission projects include resource portfolio evolution, Order 1000 compliance and changes to the MISO footprint. Two key policy issues are currently under review to improve alignment of costs with benefits of economic and multi-value projects that include: defining cost allocation of sub 345 kV economic projects (i.e. lower voltage Market Efficiency Projects) and refine cost allocation for multi-value projects (i.e. changes to the 100 percent postage stamp allocation). MISO will continue to work with stakeholders to develop a proposal that addresses the two key policy issues. This proposal is expected to be presented in January 2018. MISO will then work with stakeholders to refine the proposal in preparation for a FERC filing later in 2018. The effective date of any cost allocation changes is intended to coincide with the conclusion of the cost allocation transition period for MISO South membership expansion.

The objective of MISO transmission cost allocation methodologies is to align as best as possible who pays with who benefits over time from regional transmission expansion.

Conclusion

MISO is proud of its independent, transparent and inclusive planning process that is well-positioned to study and address future regional transmission and policy-based needs. The valuable input and support from the stakeholder community allows MISO to create well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. MISO welcomes feedback and comments from stakeholders, regulators and interested parties on the evolving electricity system and implementation of MISO's strategic initiatives. For detailed information about MISO, MTEP17, renewable energy integration, cost allocation, and other planning efforts, go to www.misoenergy.org.

Book 1 / Transmission Studies

Section 2: MTEP Overview

2.1 Investment Summary

The 353 MTEP17 new Appendix A projects represent $2.7 billion[9] in transmission infrastructure investment and fall into the following categories:

- **76 Baseline Reliability Projects (BRP) totaling $953 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).

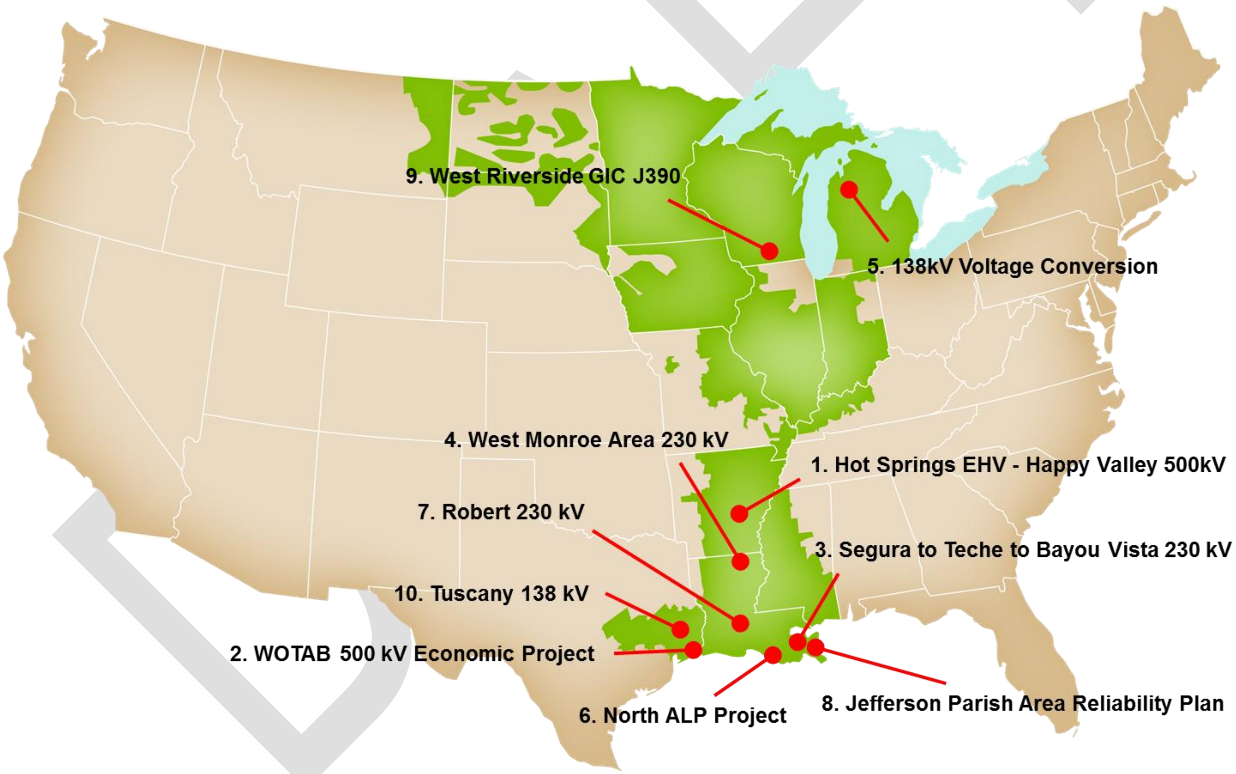


Figure 2.1-1: Top 10 MTEP17 new Appendix A projects (in descending order of cost)

9 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	$64,132,673				$310,344,000	**$374,476,673**
East	$53,193,017	$12,396,000		$4,918,500	$341,440,000	**$411,947,517**
South	$769,535,032	$31,440,000	$129,679,192		$328,882,226	**$1,259,536,450**
West	$65,847,908	$193,779,548			$412,783,386	**$672,410,842**
Total	**$952,708,630**	**$237,615,548**	**$129,679,192**	**$ 4,918,500**	**$1,393,449,612**	**$2,718,371,482**

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.

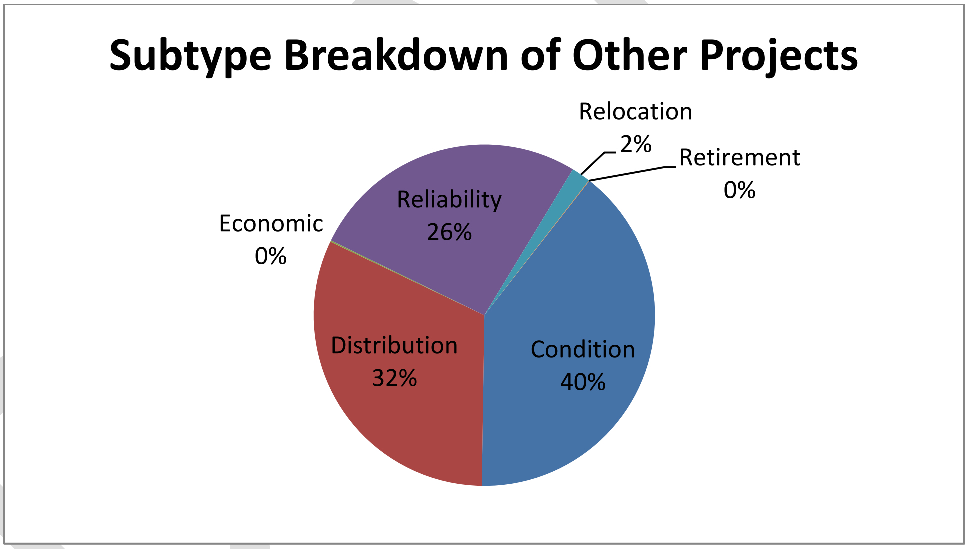


Figure 2.1-2: Subtype breakdown of new MTEP17 Appendix A Other projects

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.

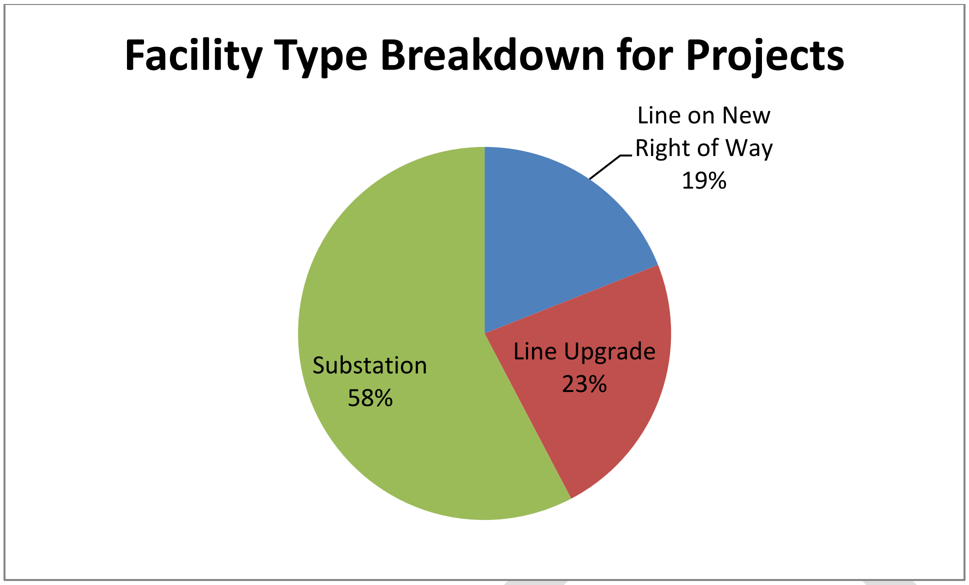


Figure 2.1-3: Facility type for new MTEP17 Appendix A projects

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.

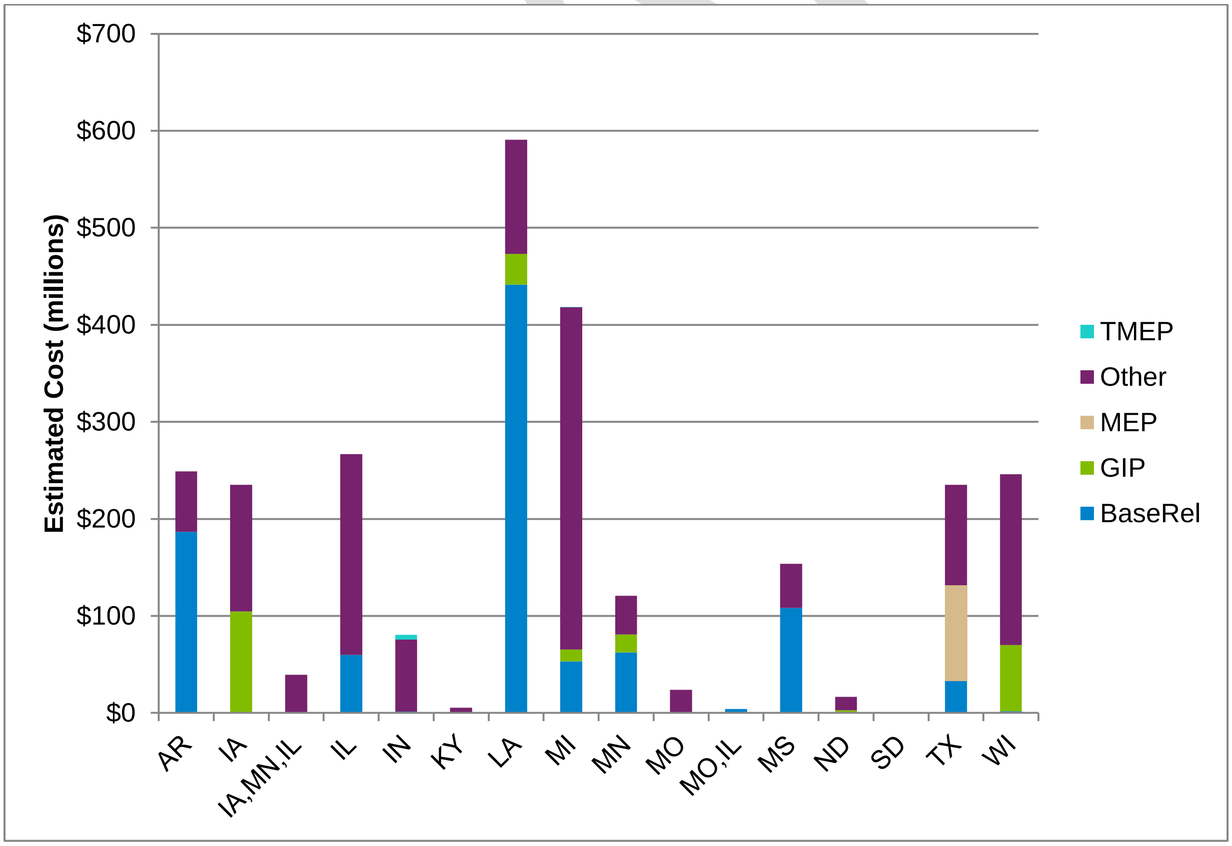


Figure 2.1-4: New MTEP17 Appendix A investment categorized by state

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.

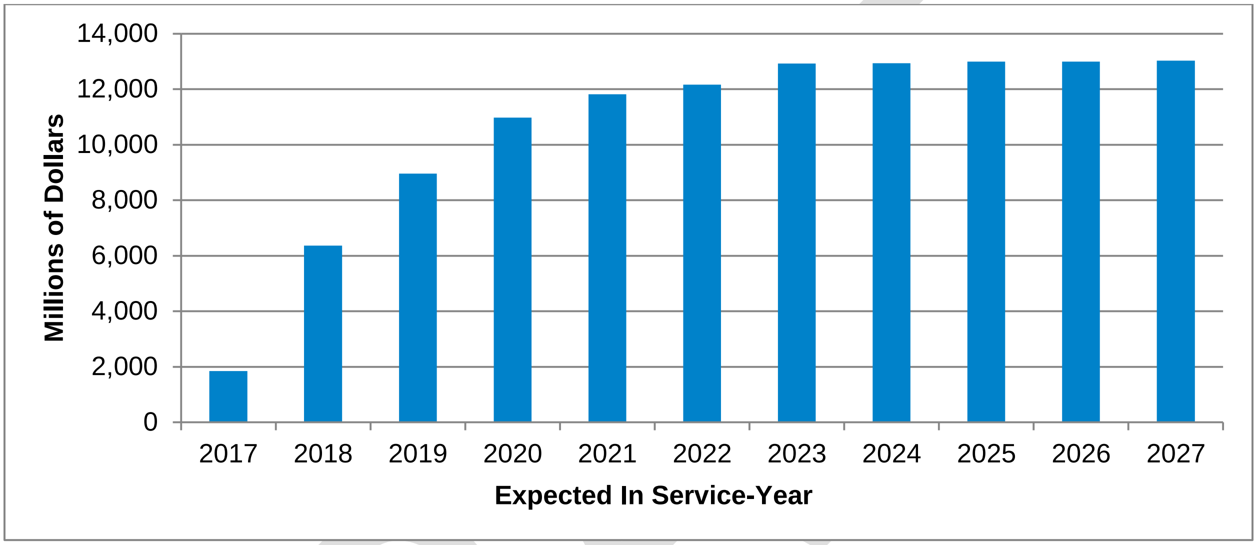


Figure 2.1-5: MTEP17 Appendix A projected cumulative investment by year

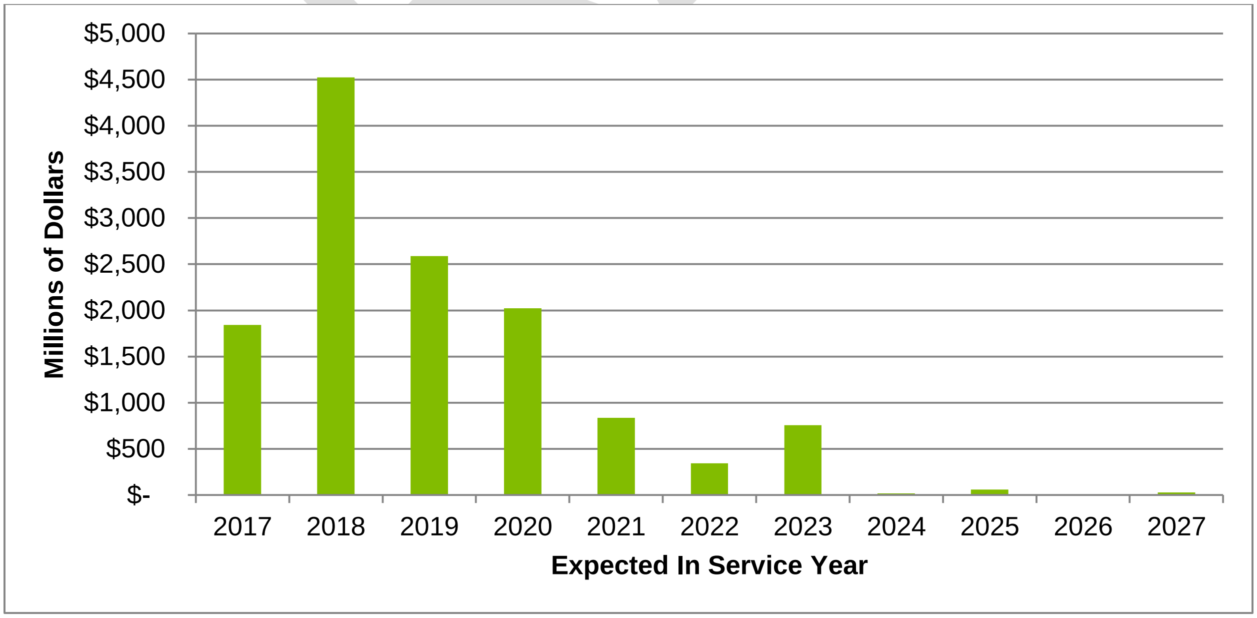


Figure 2.1-6: MTEP17 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[10] 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

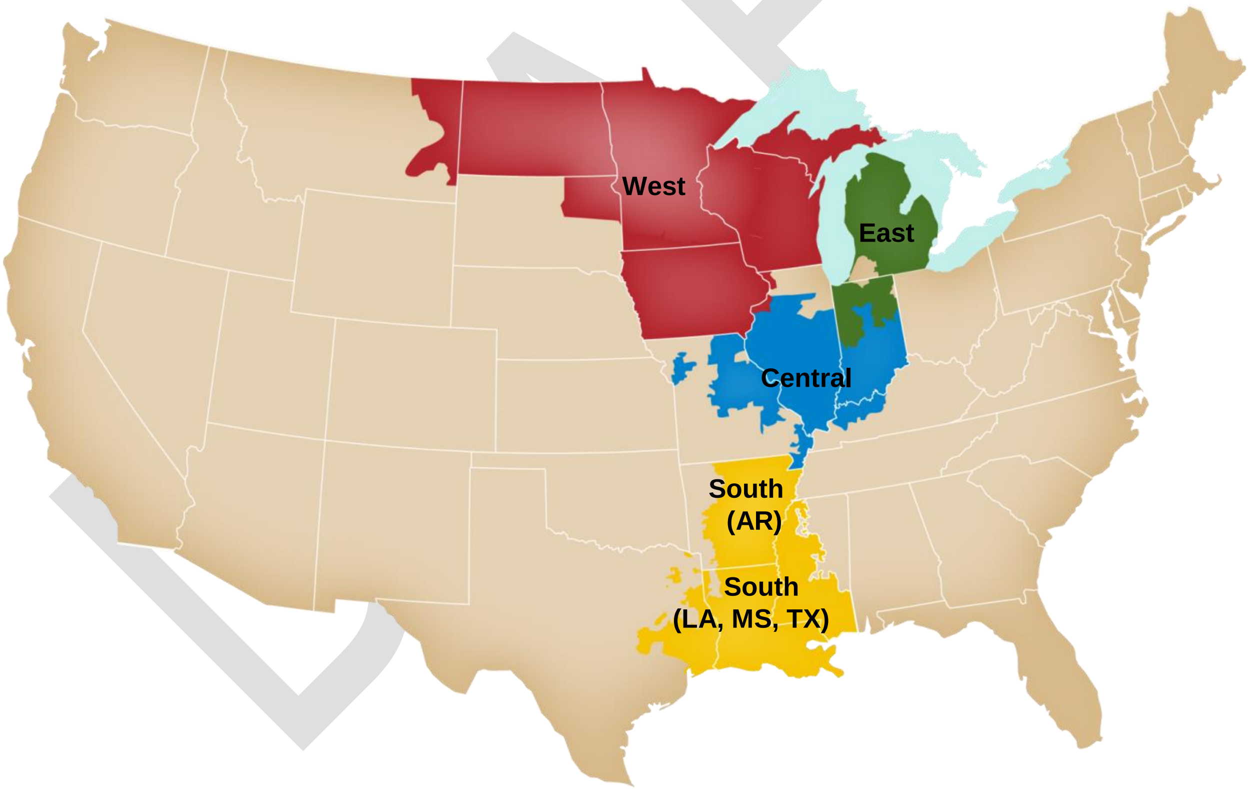


Figure 2.1-7: MISO footprint and planning regions

10 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

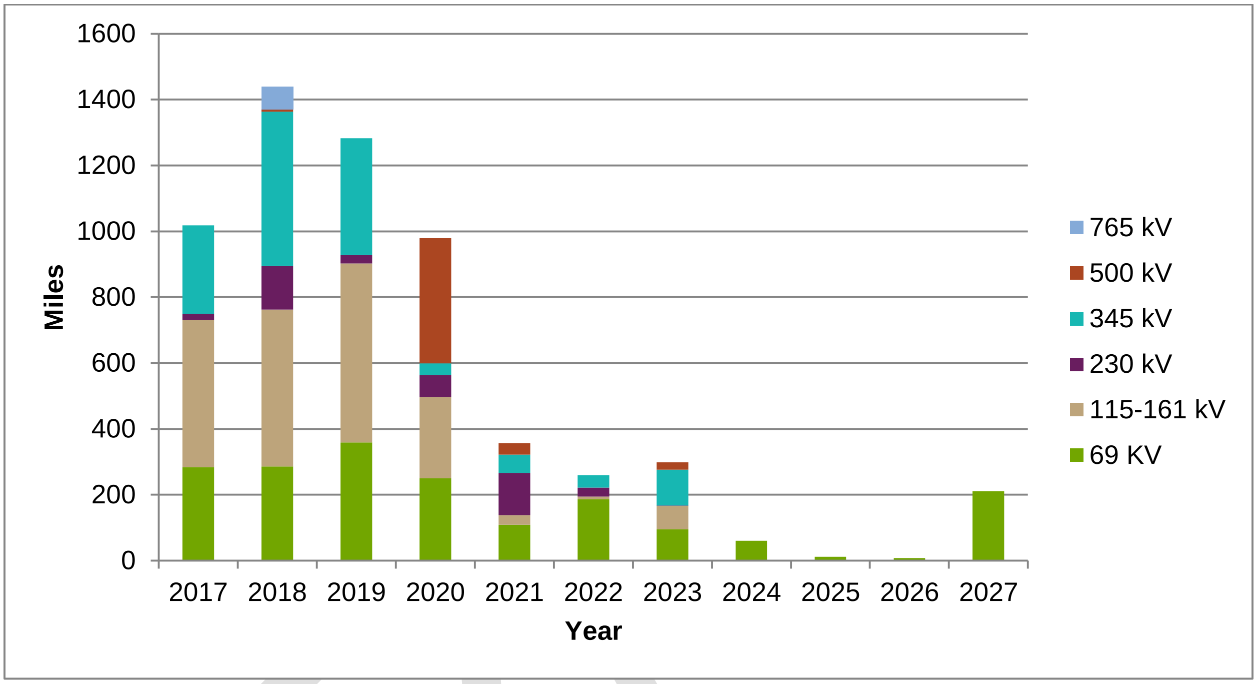


Figure 2.1-8: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2027

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 15 new cost-shared projects, with a total shared project cost of $176 million for inclusion in Appendix A. The 15 cost-shared projects include:

- 9 Generator Interconnection Projects (GIP) with a total project cost of $153 million, with $41 million allocated to load and the remaining $112 million allocated directly to generators[11]
- 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.[12] For MEPs, a portion of costs are distributed to the local resource 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 $53.9 million of the approved costs for GIPs, MEPs, and TMEPs are allocated to the pricing zone where the project is located. The remaining $121.7 million is allocated to neighboring pricing zones or to all pricing zones system-wide (within the applicable planning area).

In MTEP17, approximately $53.9 million of the approved costs for GIPs, MEPs and TMEPs is allocated to the pricing zone where the project is located. The remaining $121.7 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.[13]

---

[11] 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.

[12] See Chapter 5.1 for more information on project cost allocation.

[13] 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

The cost-shared projects in MTEP17 all terminate 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[14] (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) — 82 projects, $679 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)

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.

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

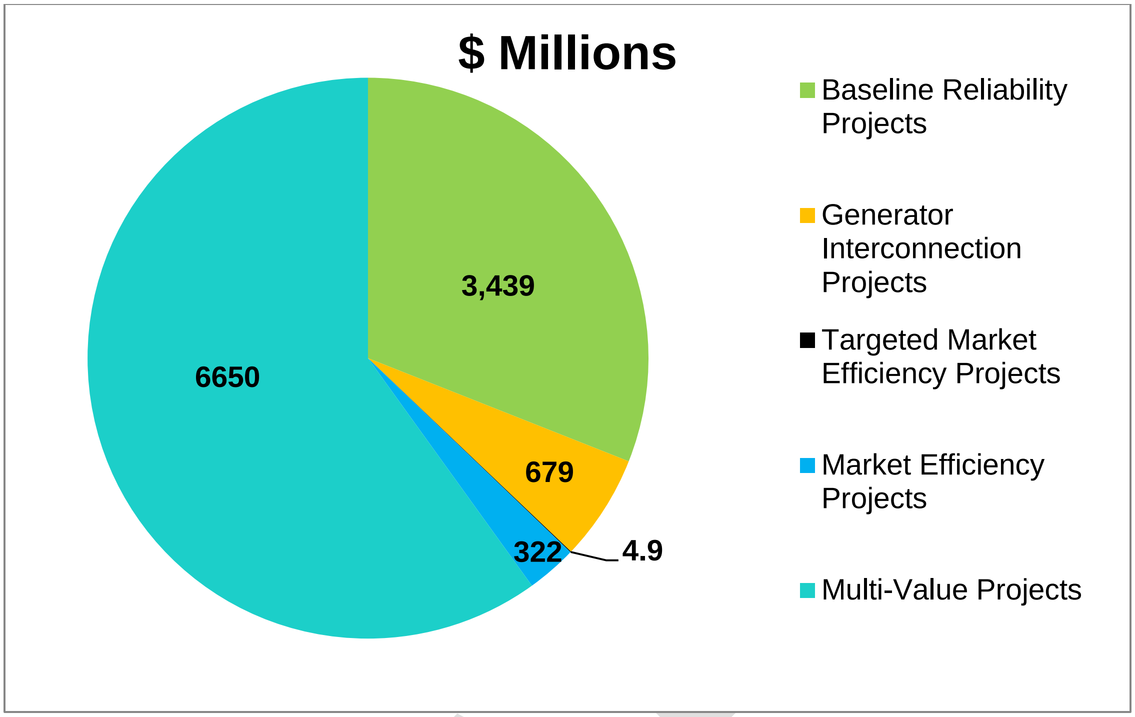


Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

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	$153.3	$129.7	$4.9	$0.0	**$283.0**
Total	**$3,439.5**	**$679.0**	**$322.7**	$4.9	**$6,650.0**	**$11,091.0**

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[15] (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).[16] 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.

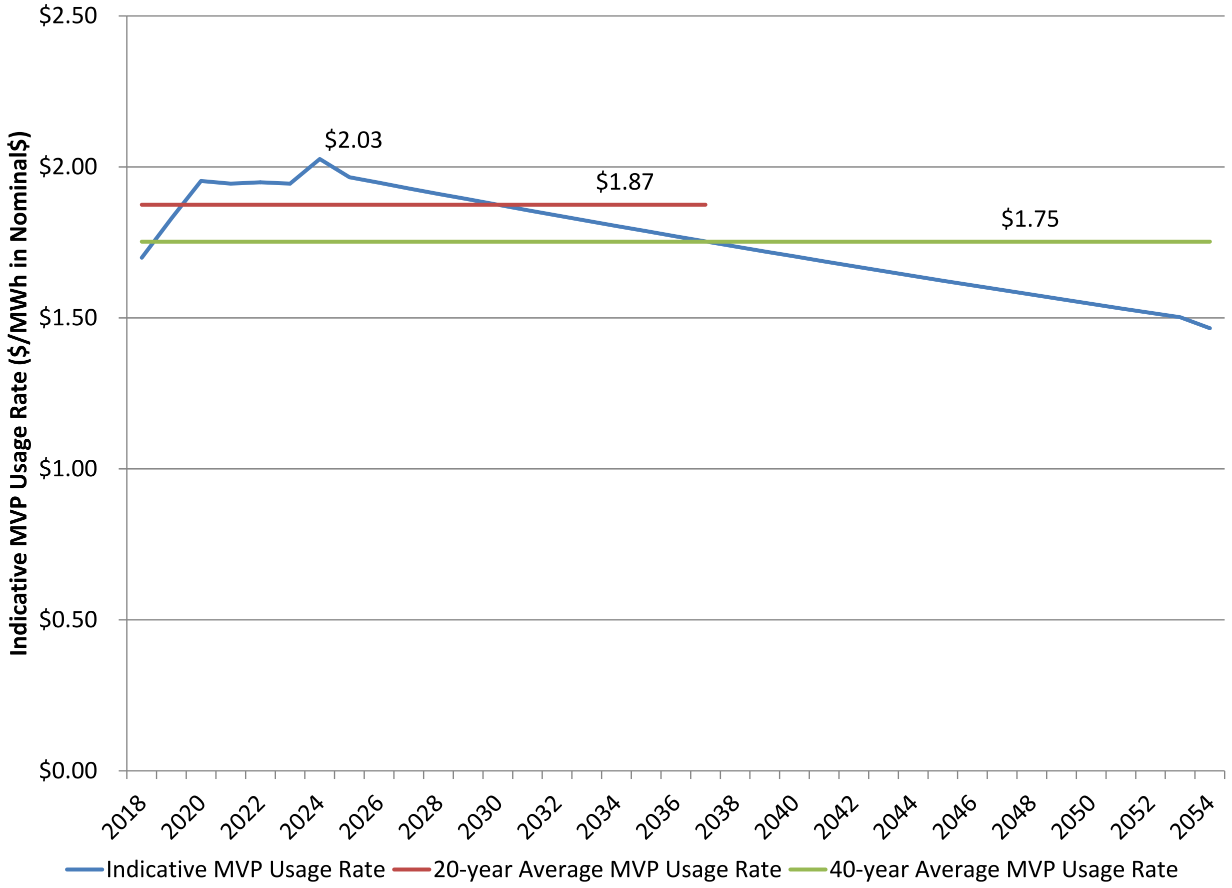


Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2017 to 2054

[15] 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.

[16] 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.

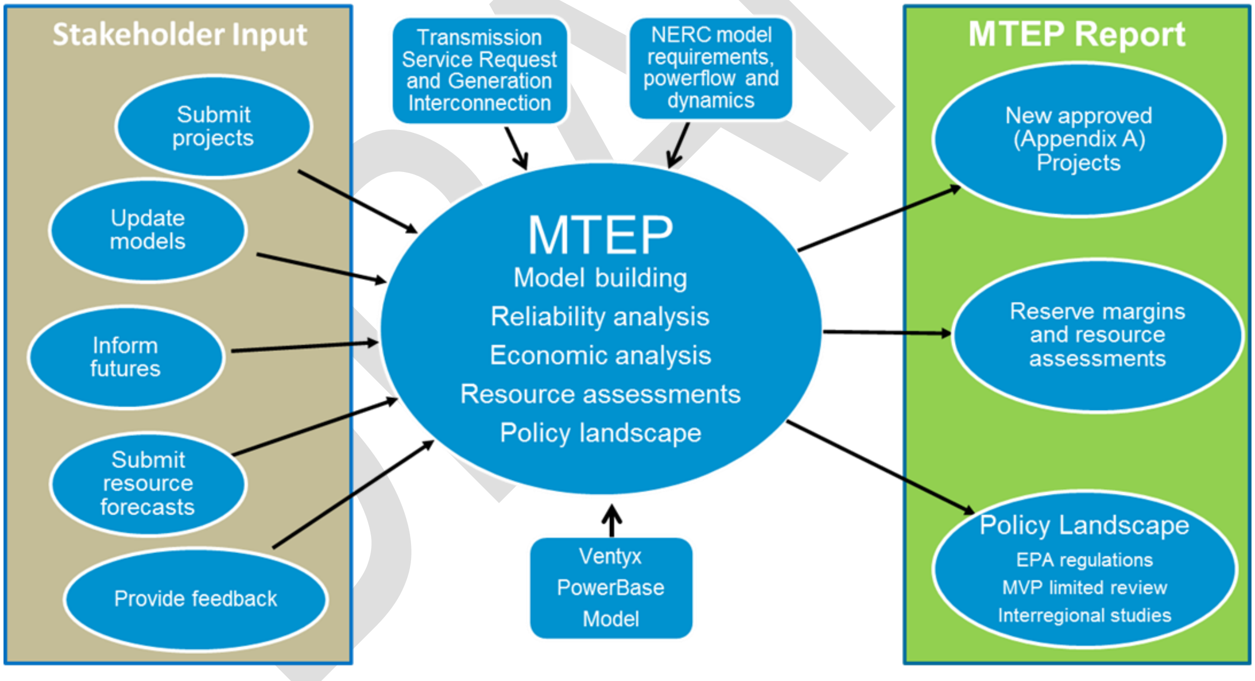


Figure 2.3-1: MTEP inputs and outputs

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.

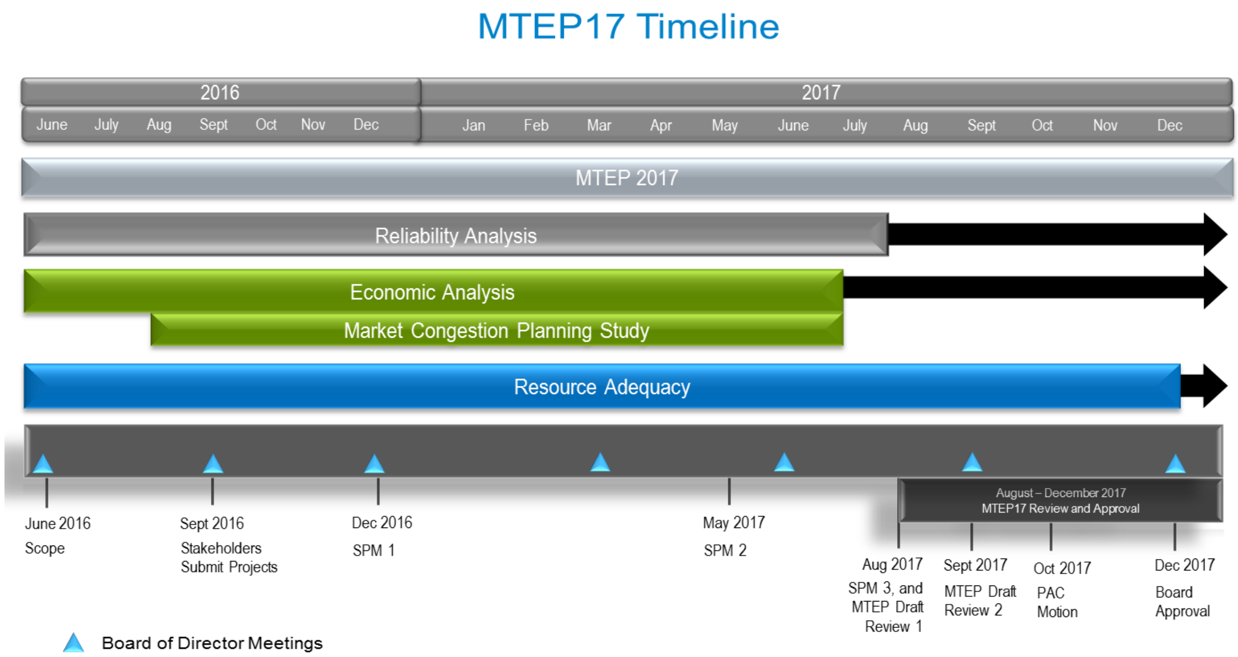


Figure 2.3-3: MTEP17 timeline

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.[17]

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[18]. 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.

[17] 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.
[18] 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.

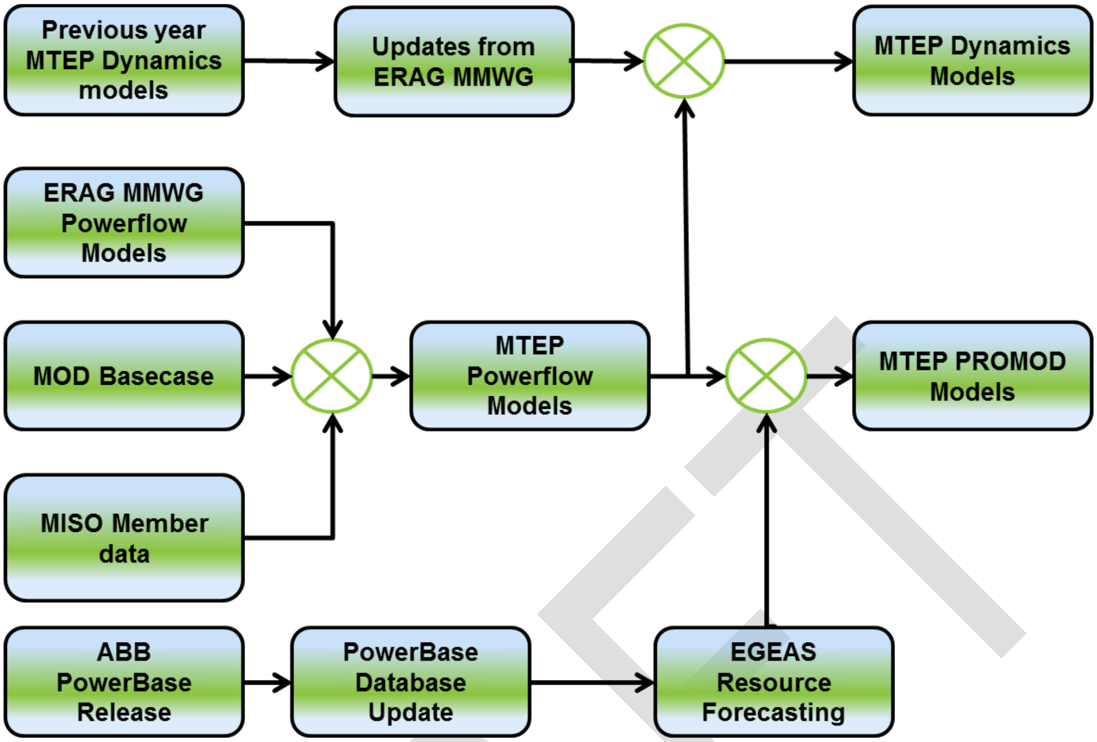
MTEP17 model-building continues MISO's submittal of modeling data to Eastern Interconnection model development per MOD-032-1

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[19]. 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

[19] 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:[20]

- Existing Fleet
- Policy Regulations
- Accelerated Alternative Technologies

[20] 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.

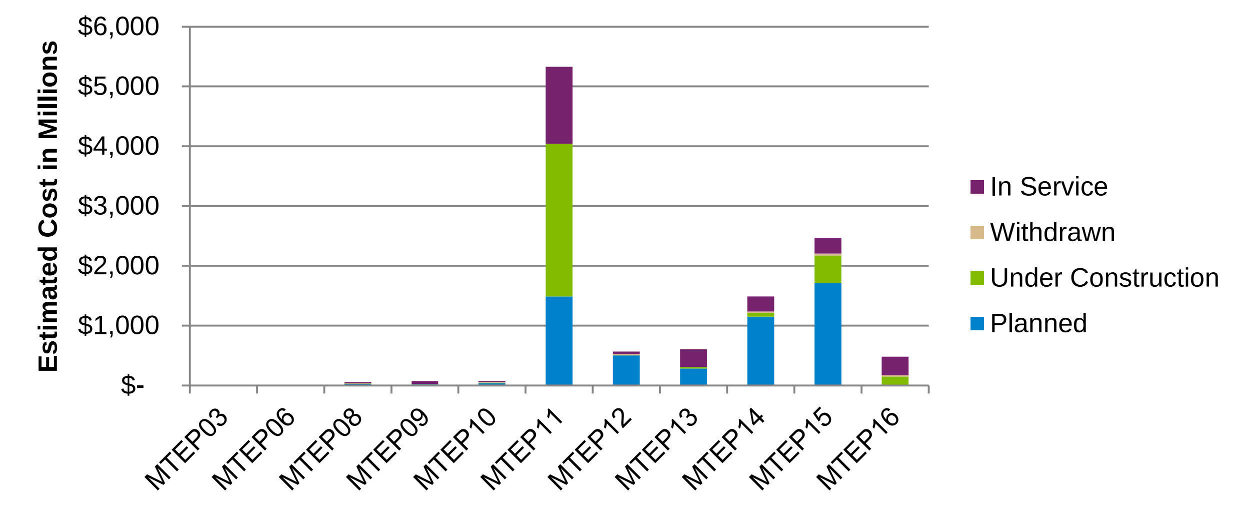


Figure 3.1-1: Project Status of Active Projects

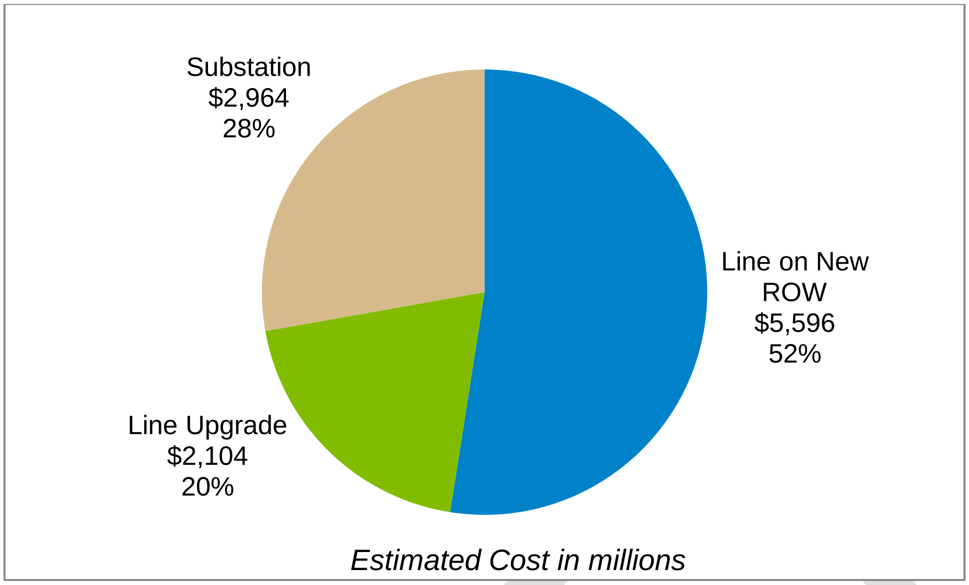


Figure 3.1-2: Facility Cost of Active Projects

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[21]:

- 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.

[21] 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

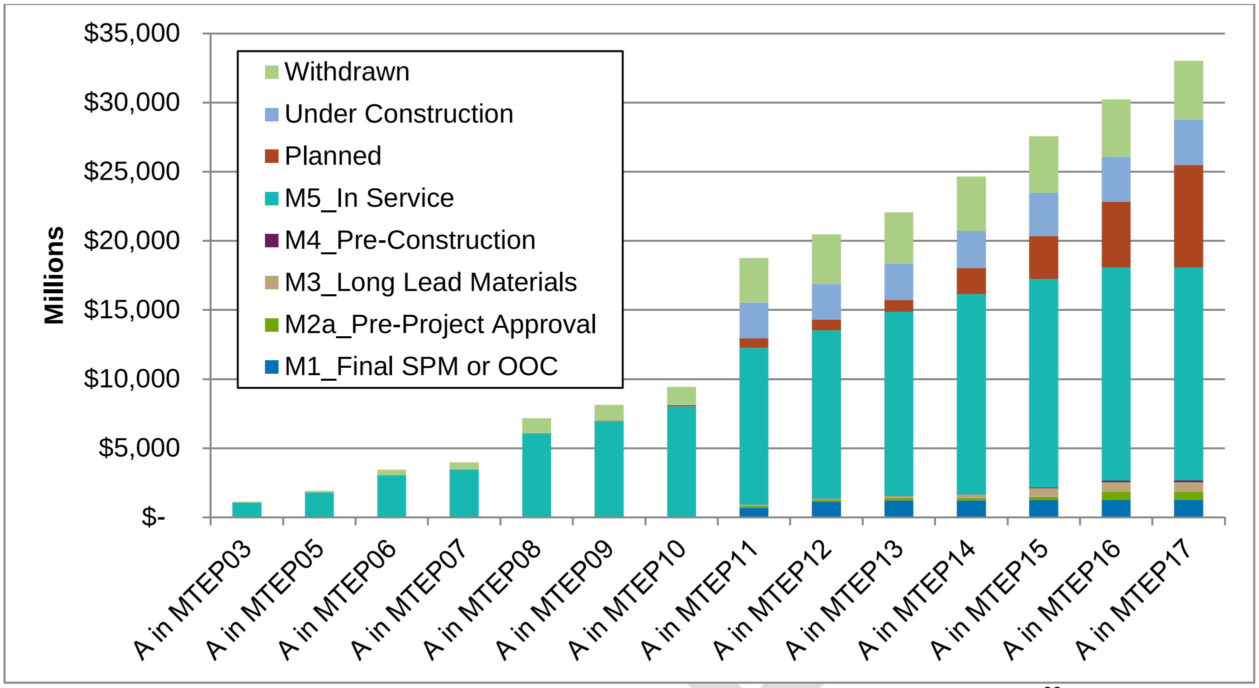


Figure 3.2-1: Cumulative transmission investment by facility status[22]

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.

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

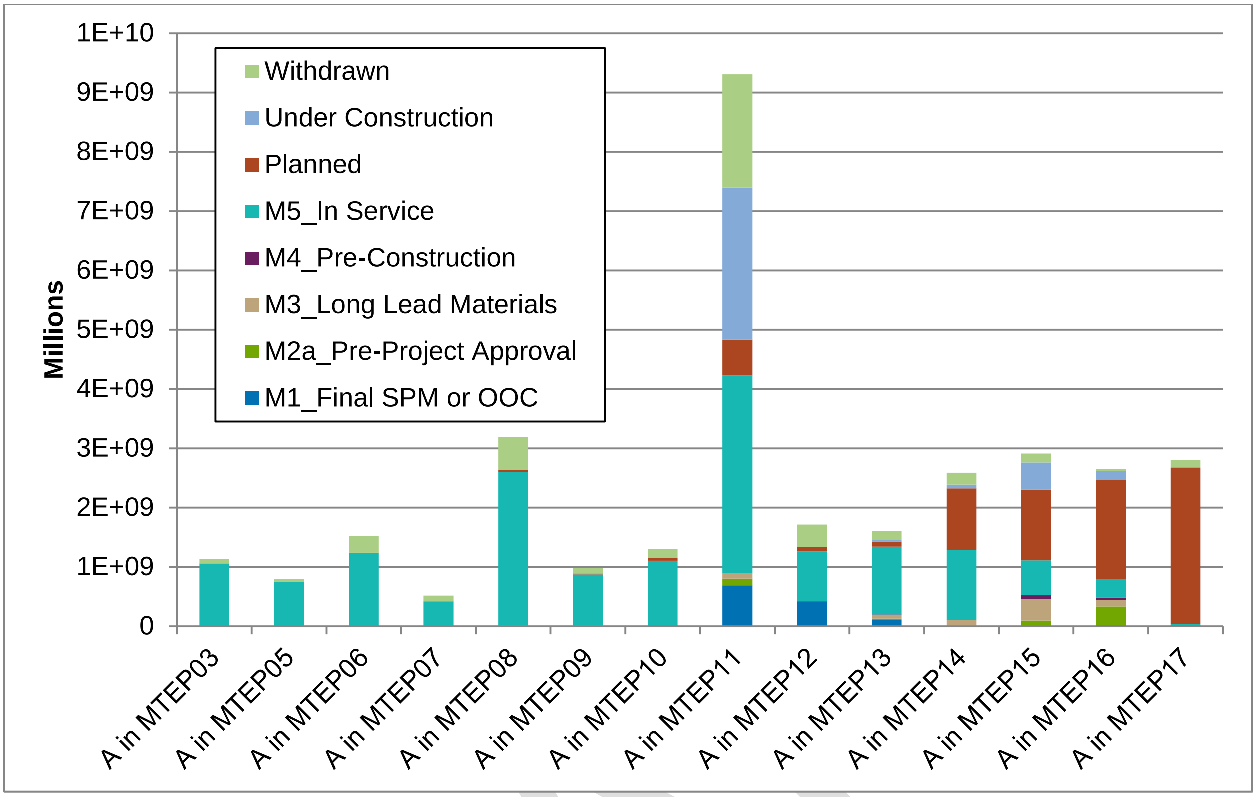


Figure 3.2-2: Approved transmission investment by MTEP cycle[23]

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.

[23] 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 Overview

4.2 Generator Interconnection Analysis

4.3 Transmission Service Requests

4.4 Generation Retirements and Suspensions — System Support Resources

4.5 Generation Deliverability Analysis Results

4.6 Long Term Transmission Rights Analysis Results

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.

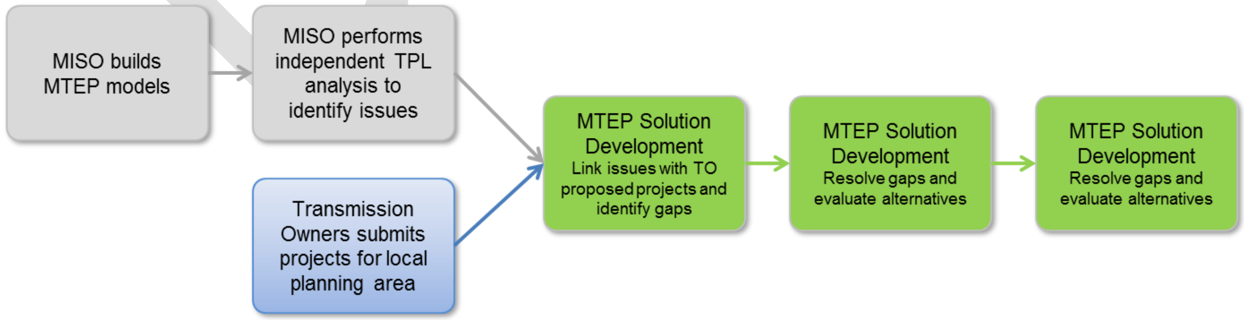


Figure 4.1-1: MTEP17 Reliability Study Process

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.[24] 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

[24] 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.

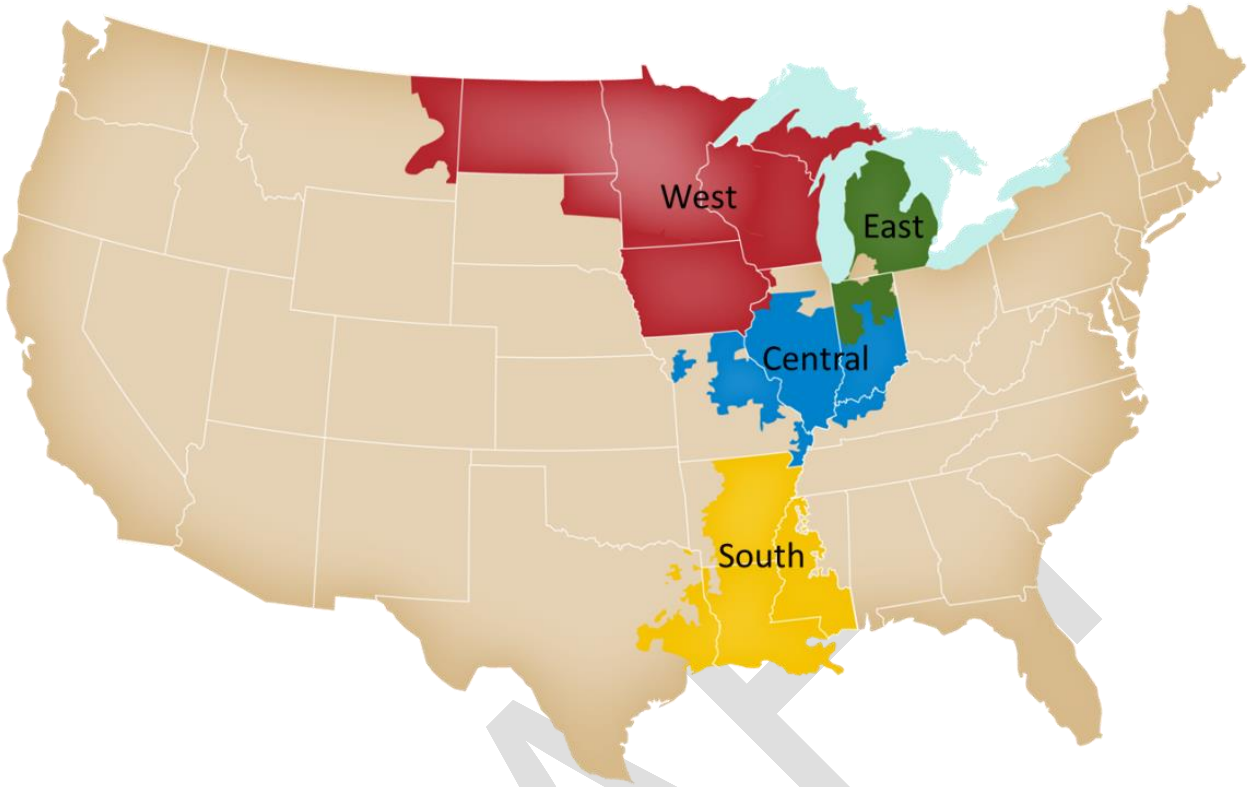


Figure 4.1-2: MISO planning subregions

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[25]

[25] 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

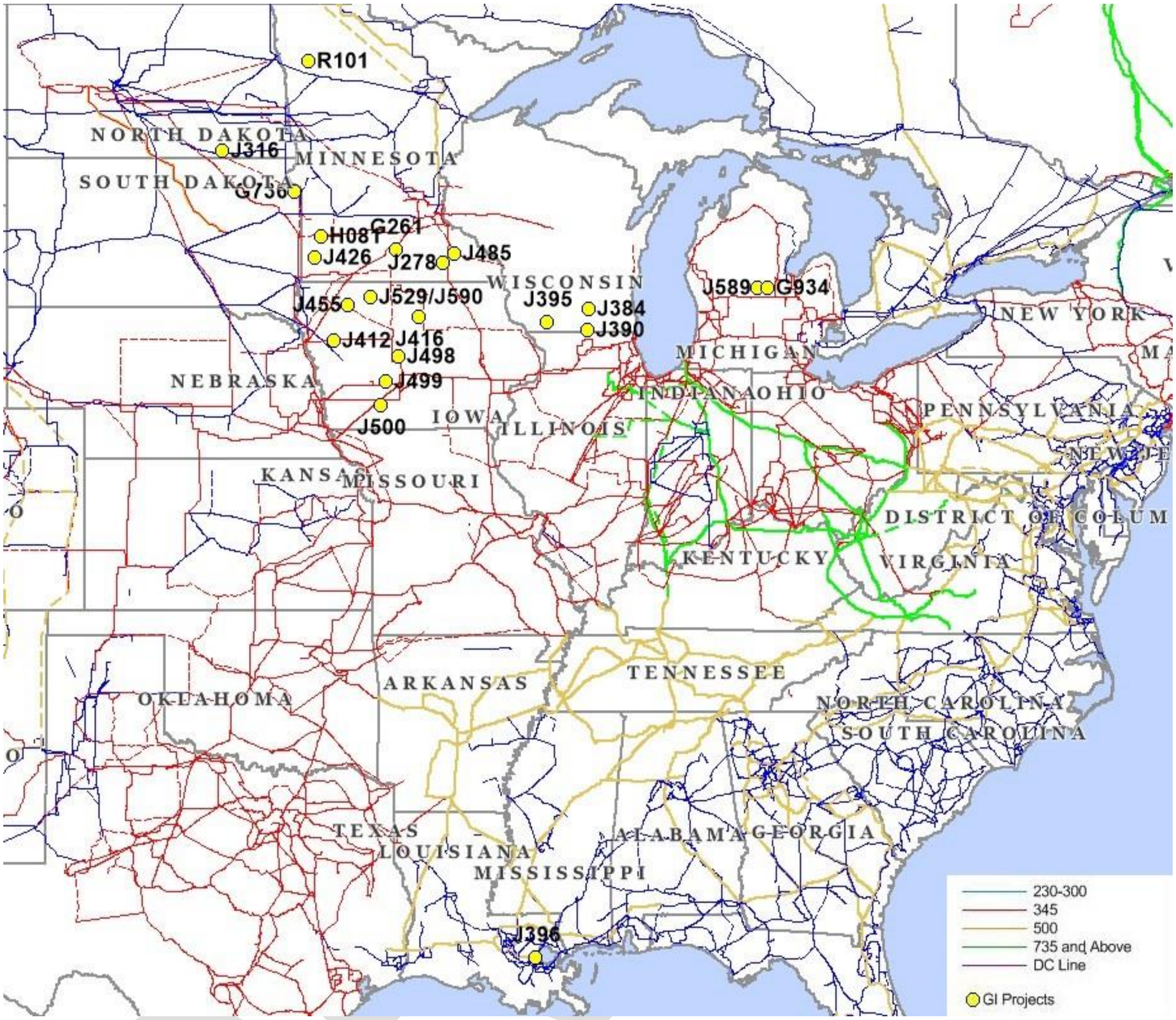


Figure 4.2-1: Generation Interconnection Requests associated with MTEP17 Target Appendix A

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.

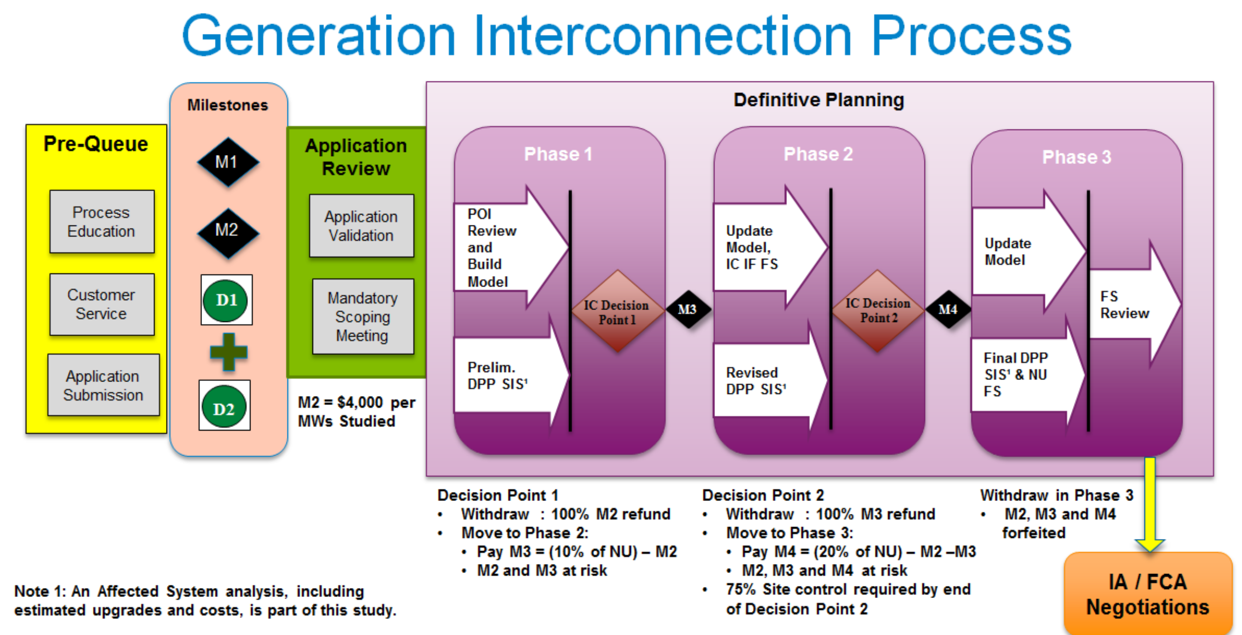
- Perform network upgrades for J412 GIP
- J412 – 200 MW Wind Generator
- Point of interconnection: LeHigh - Raun345 kV line
- Install new three-breaker 345 kV ring bus substation off the Raun – Ida 345 kV line with two taps
- Anticipated completion date: October 1, 2019
- Anticipated cost: $10,000,000

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.

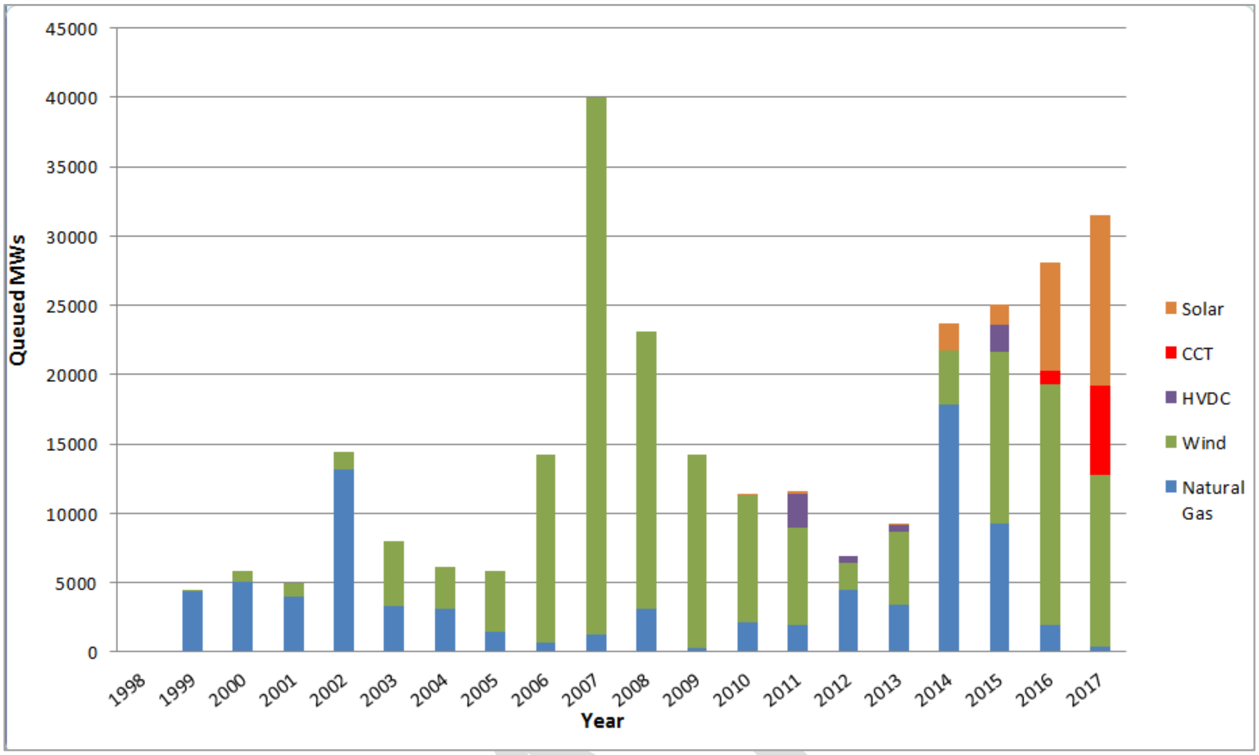
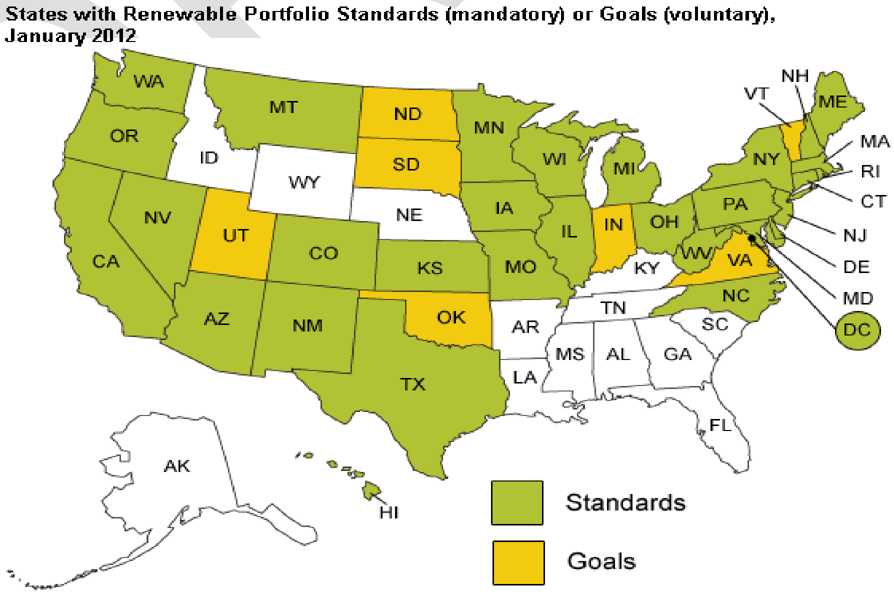


Figure 4.2-3: Queue Trends

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).



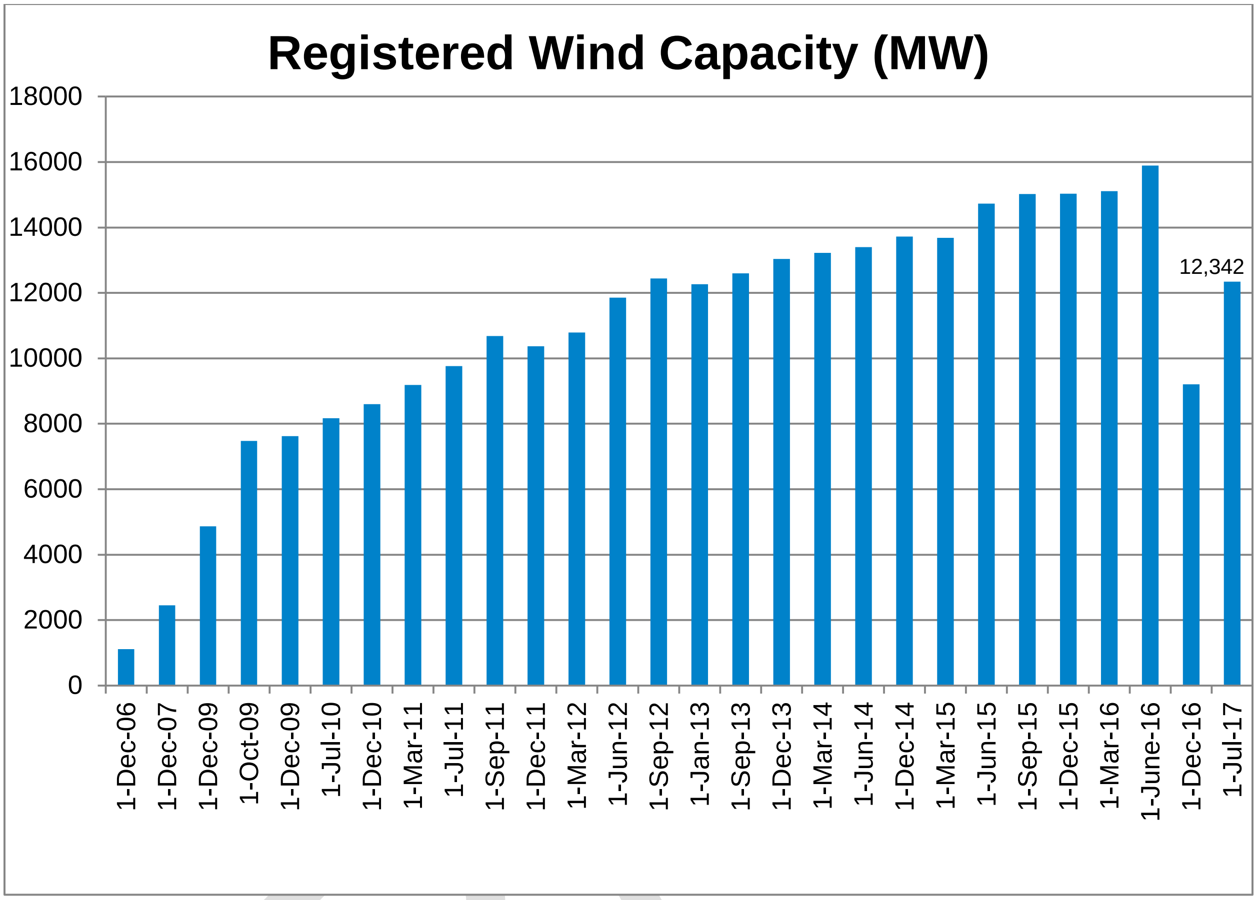


Figure 4.2-4: Nameplate wind capacity registered for MISO

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.

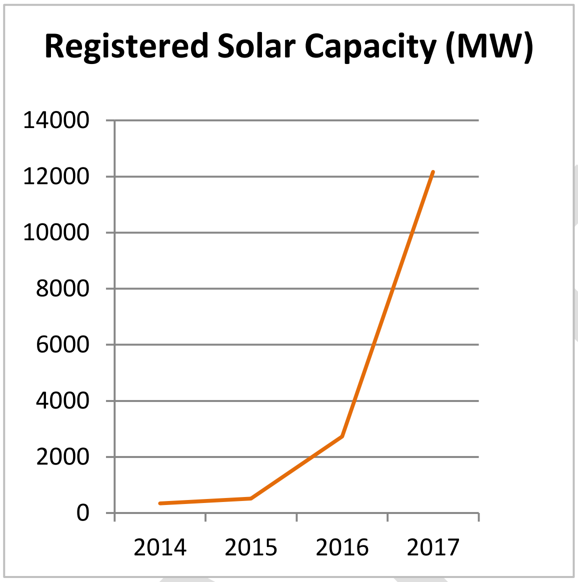


Figure 4.2-5: Solar capacity requests for MISO

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.

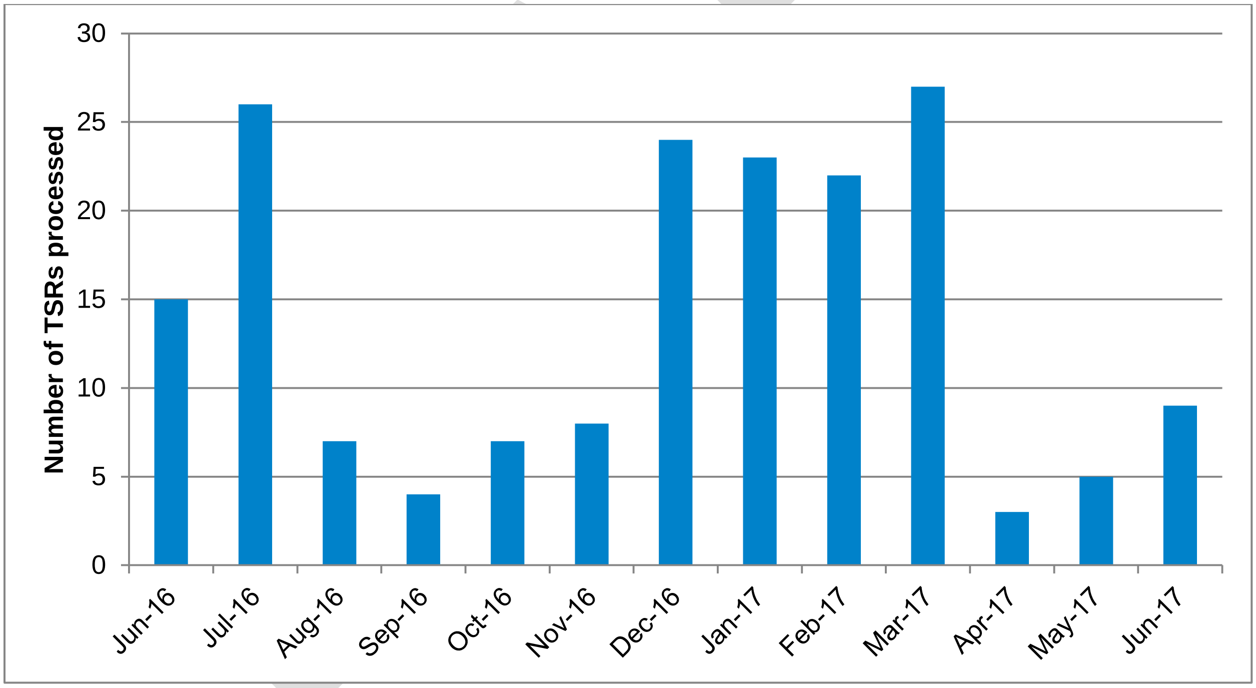


Figure 4.3-1: MISO Long-Term TSRs processed from July 2016 through June 2017

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.

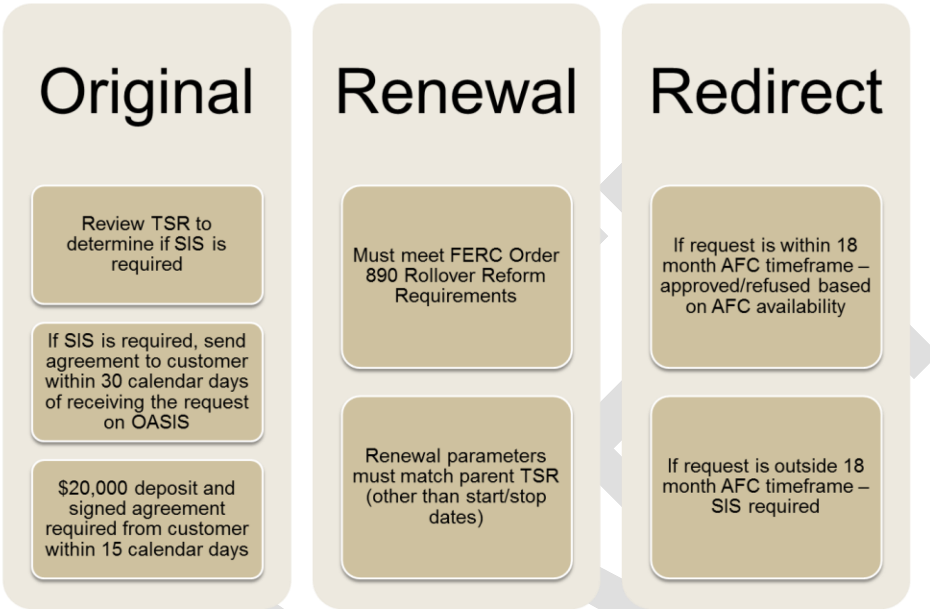


Figure 4.3-2: TSR triage phase processing

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.

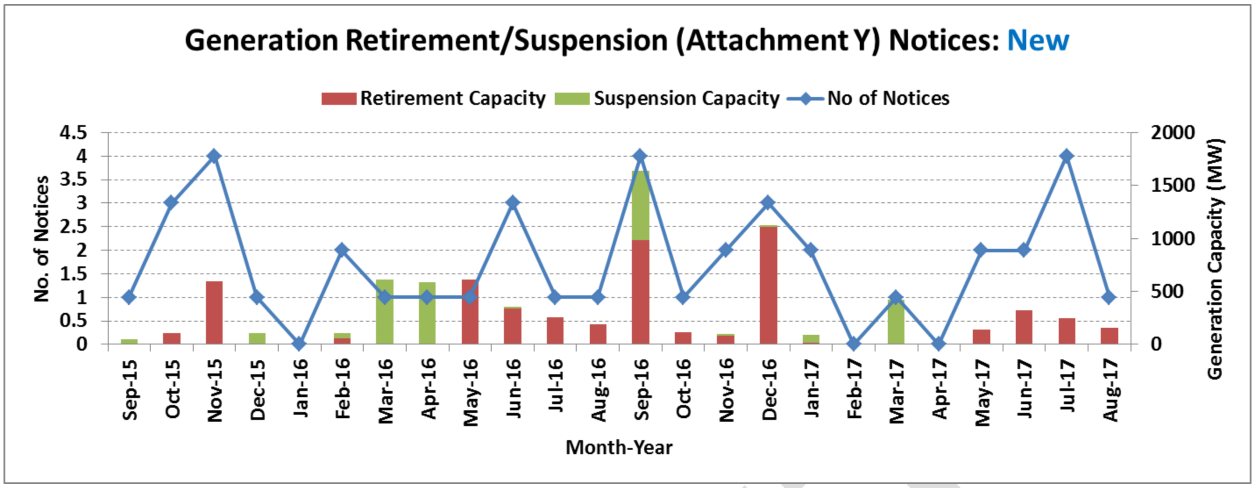
The MISO Attachment Y provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

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.



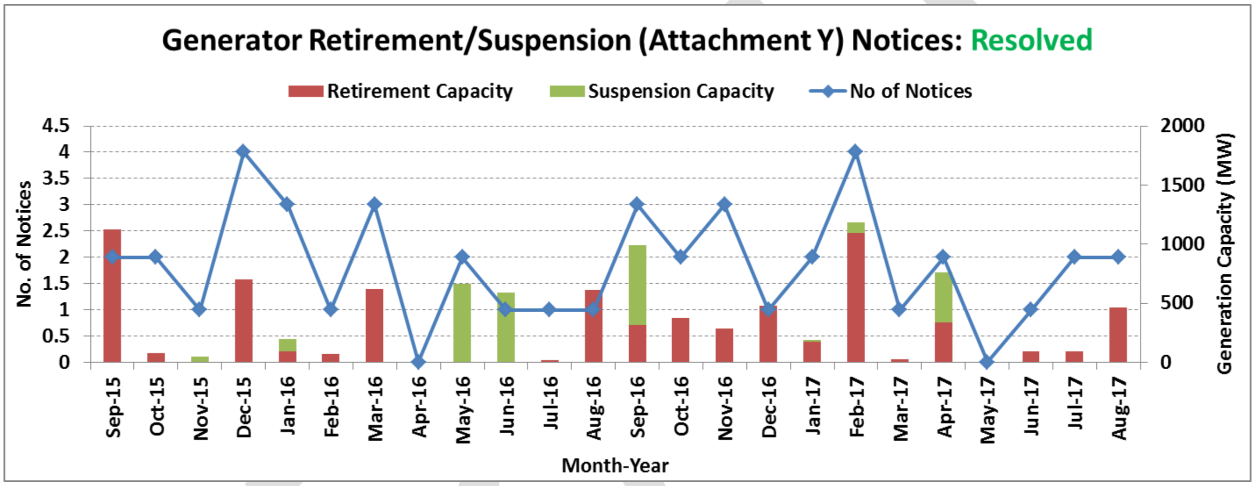


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

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.

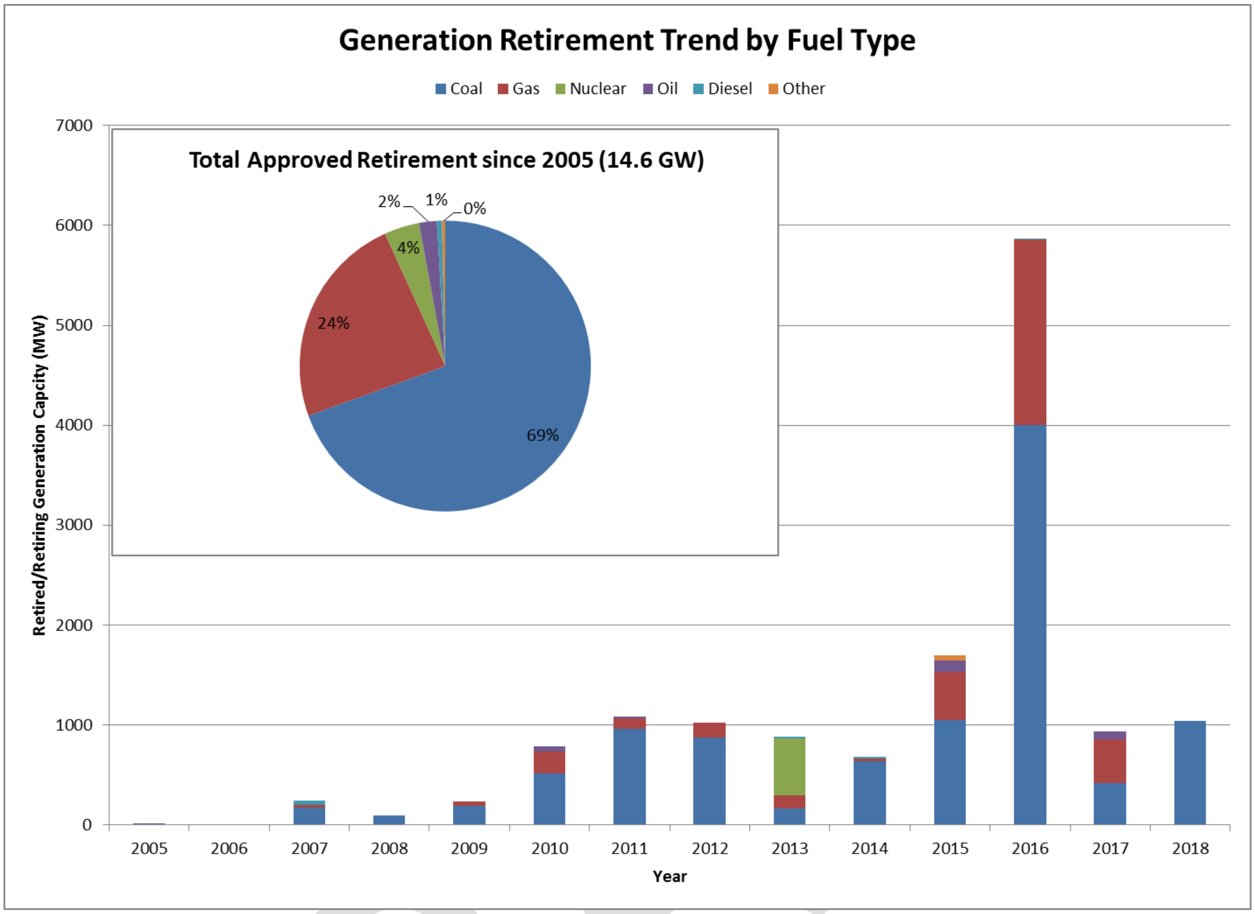


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

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.

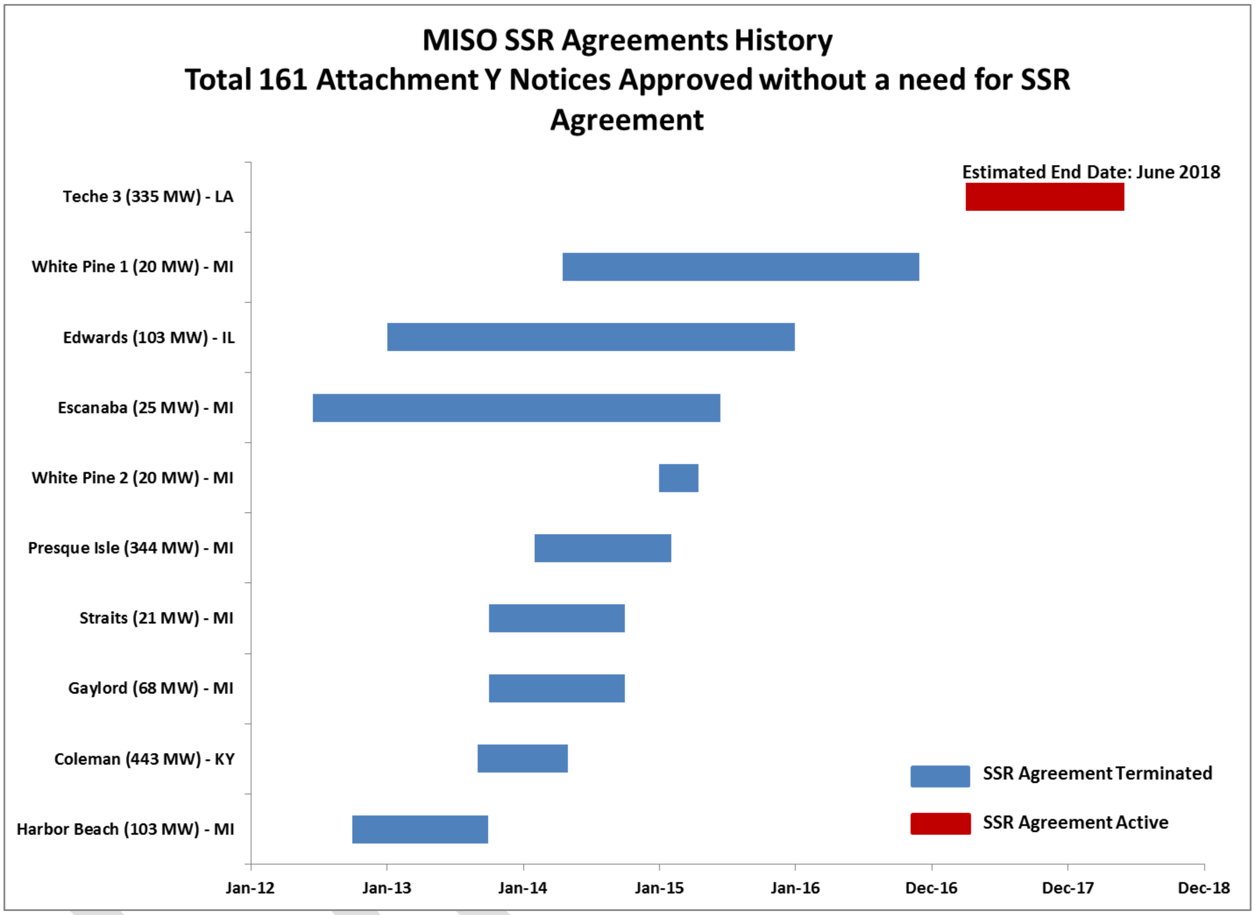


Figure 4.4-3: SSR history

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.

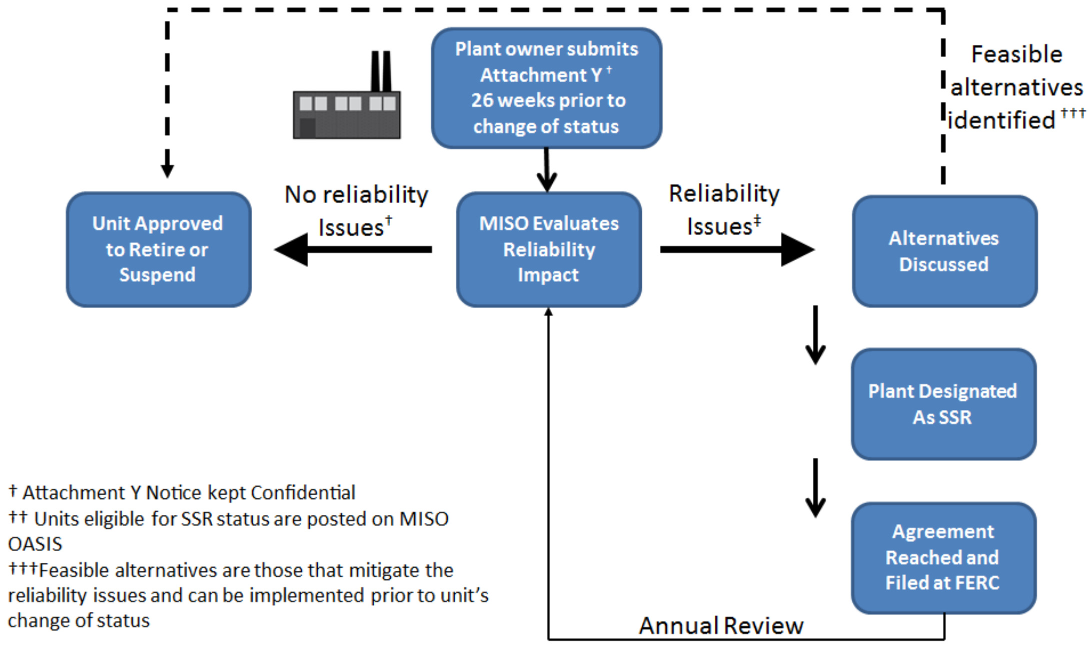


Figure 4.4-4: MISO Attachment Y process

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 1,760 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 City 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"[26] to be funded by the Interconnection Customer.

[26] 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.

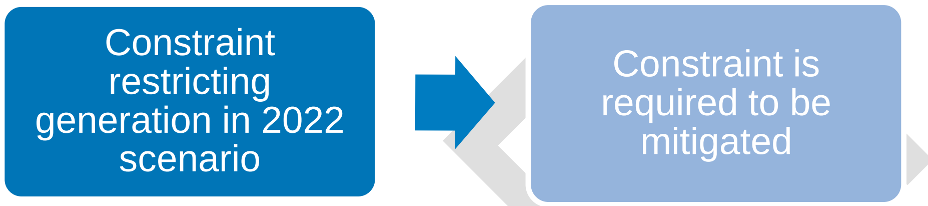
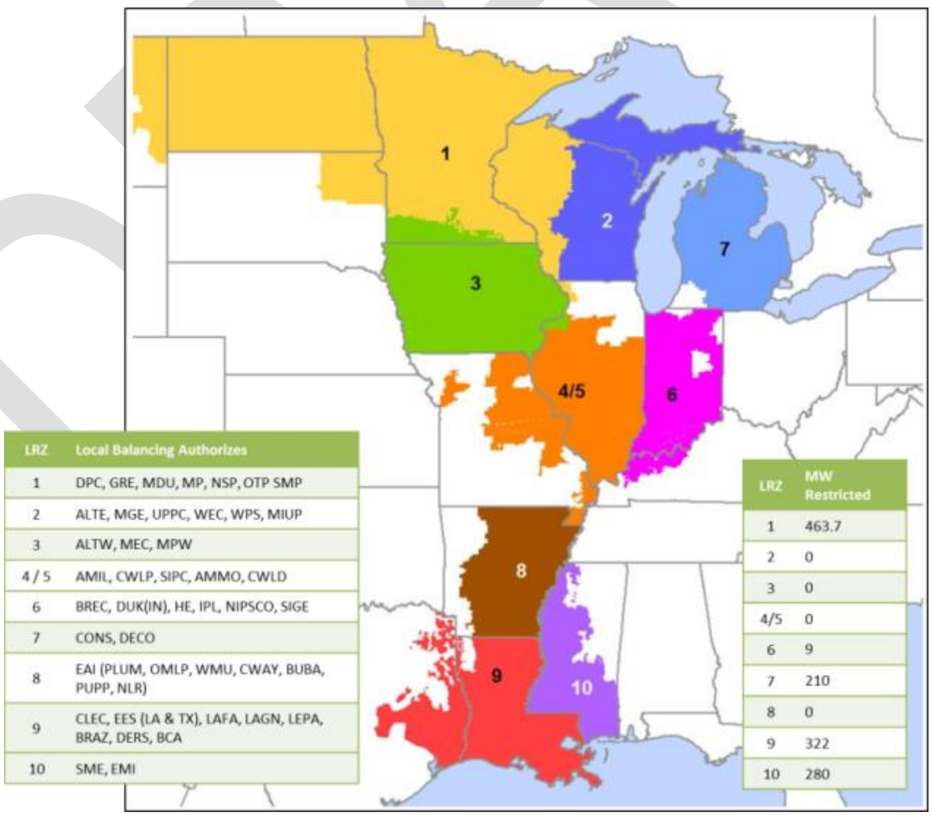


Figure 4.5-1: MTEP Deliverability Study Process Overview

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.[27]

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).

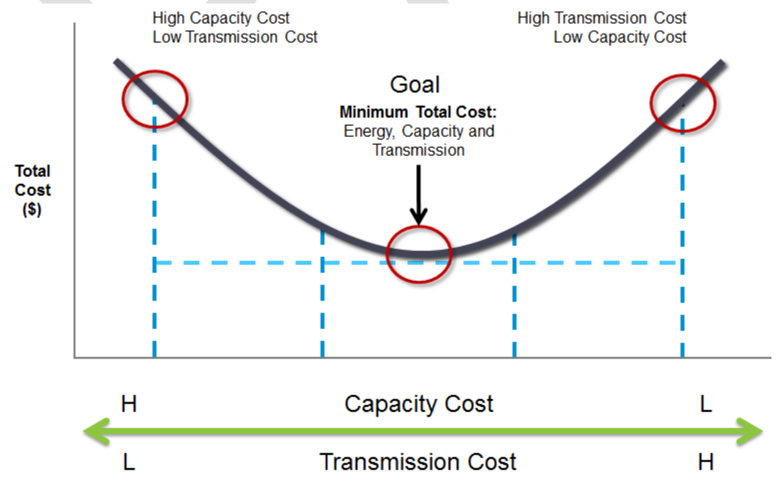


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

[27] 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.

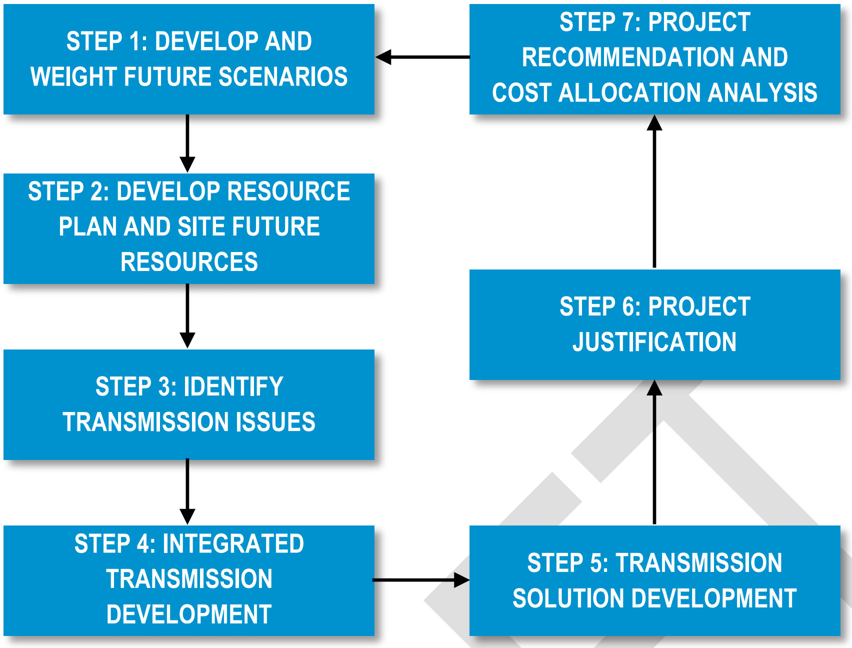


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

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 Local Resource 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[28]. 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

Slowed ***Rate of Fleet Transition*** ***Accelerated***

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

[28] 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[29].

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

[29] 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.

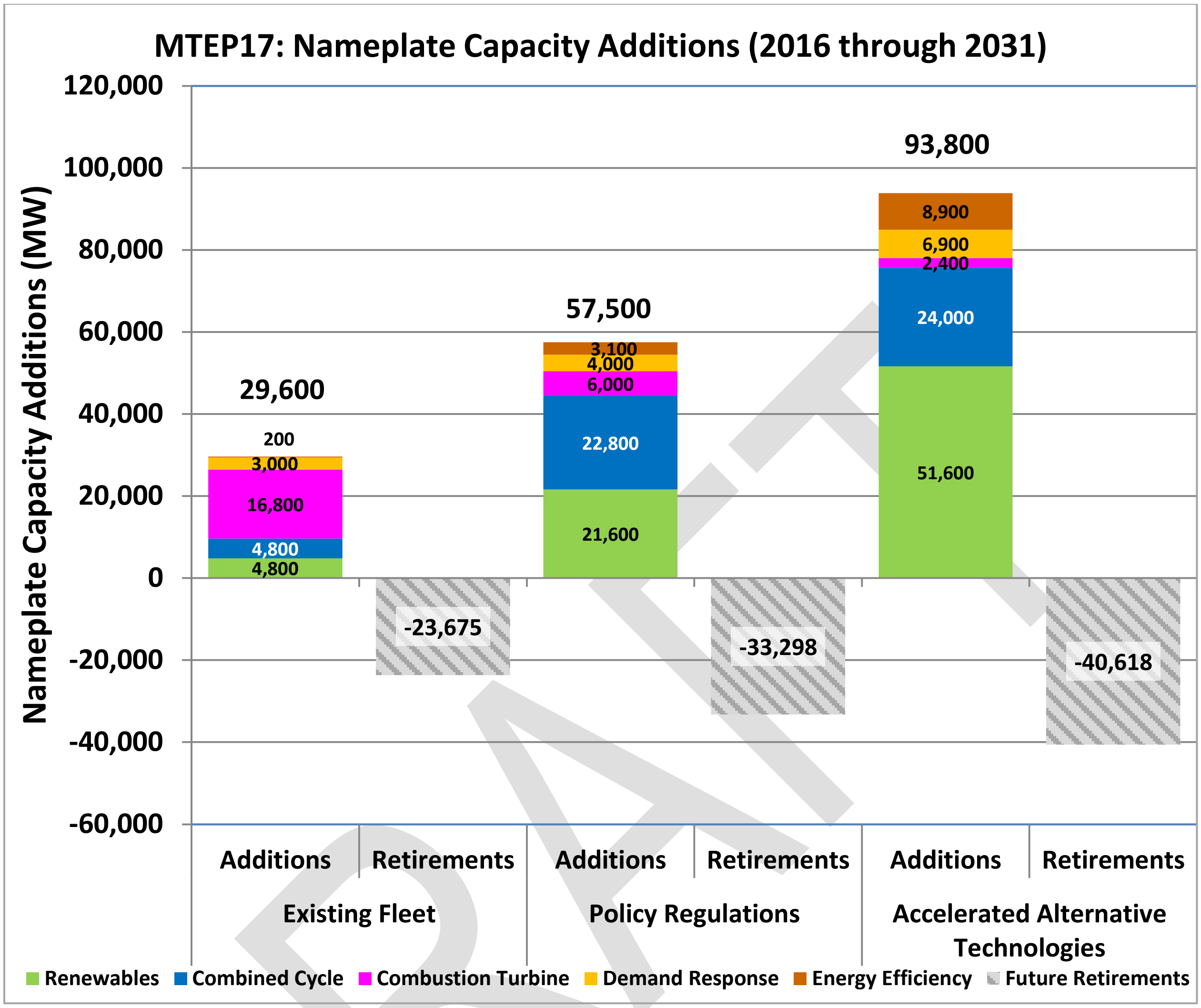
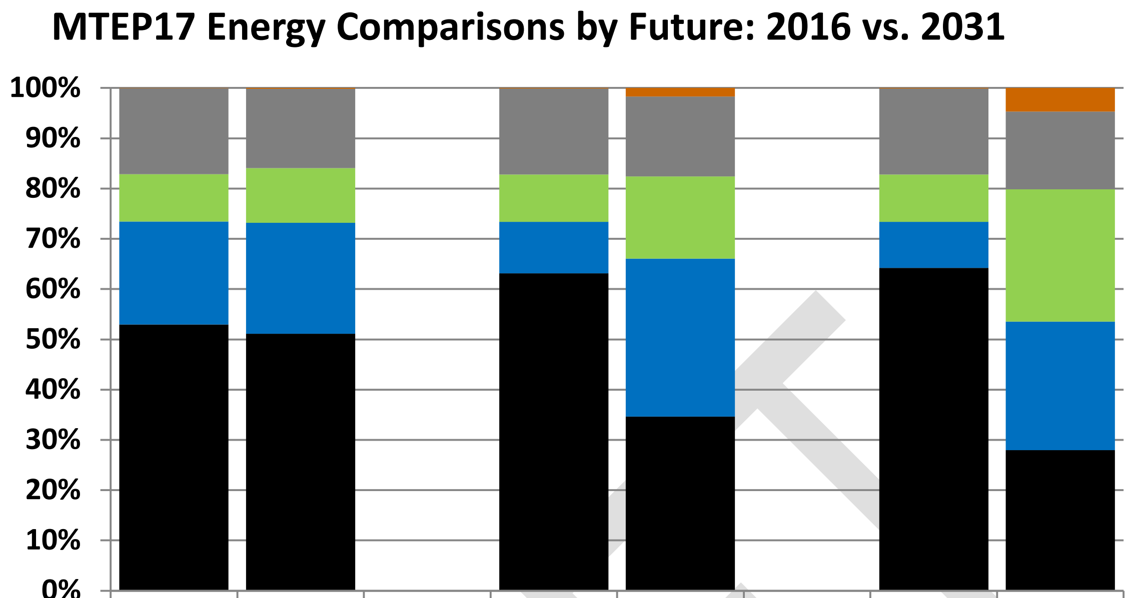


Figure 5.2-2: MISO nameplate capacity additions by future (2015-2030 EGEAS Model)[30]

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.

[30] 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[31]. 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.

[31] 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[32]. 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.

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

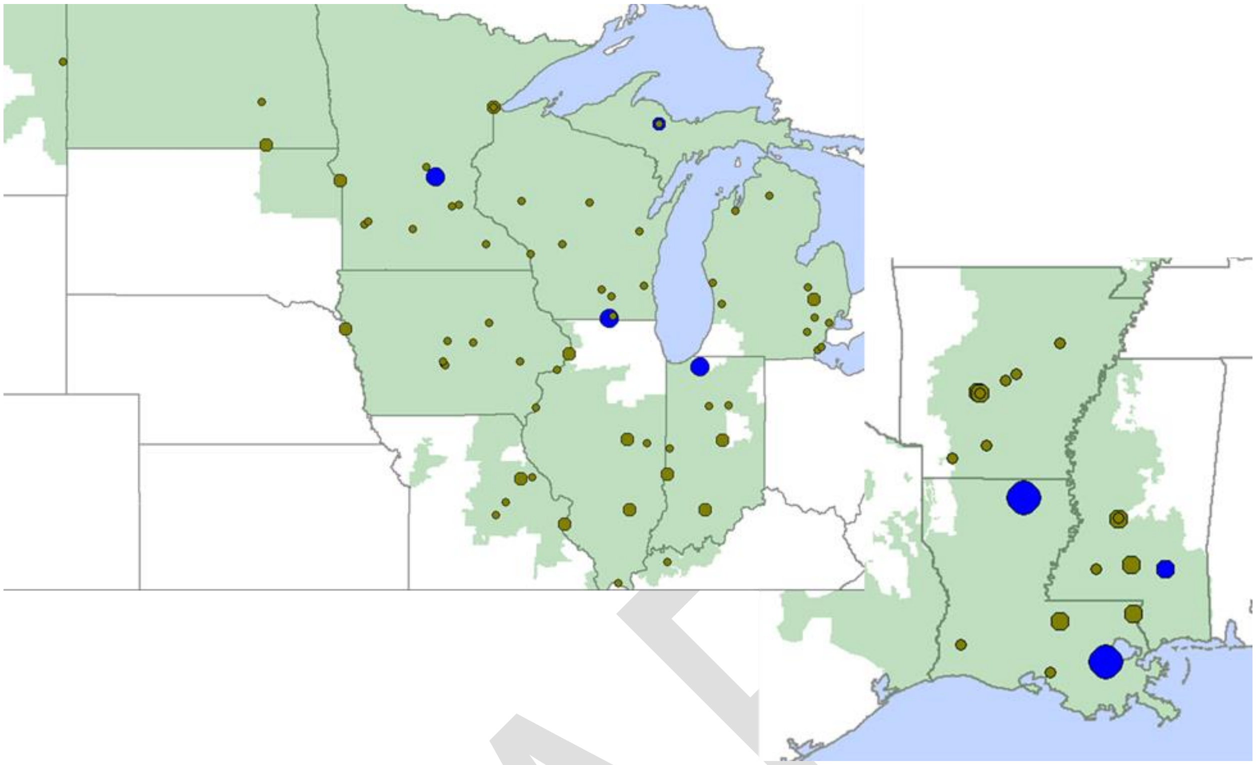


Figure 5.2-4: Existing Fleet Future Siting (MapInfo)

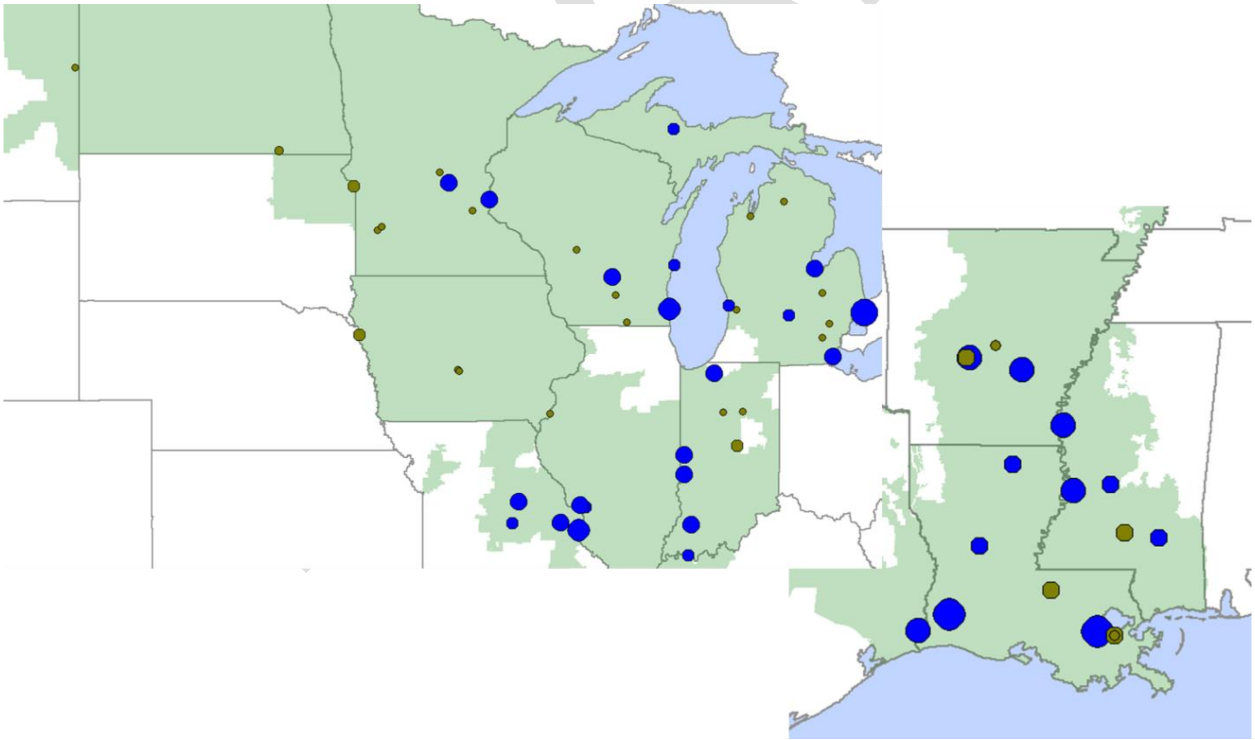


Figure 5.2-5: Policy Regulations Future Siting (MapInfo)

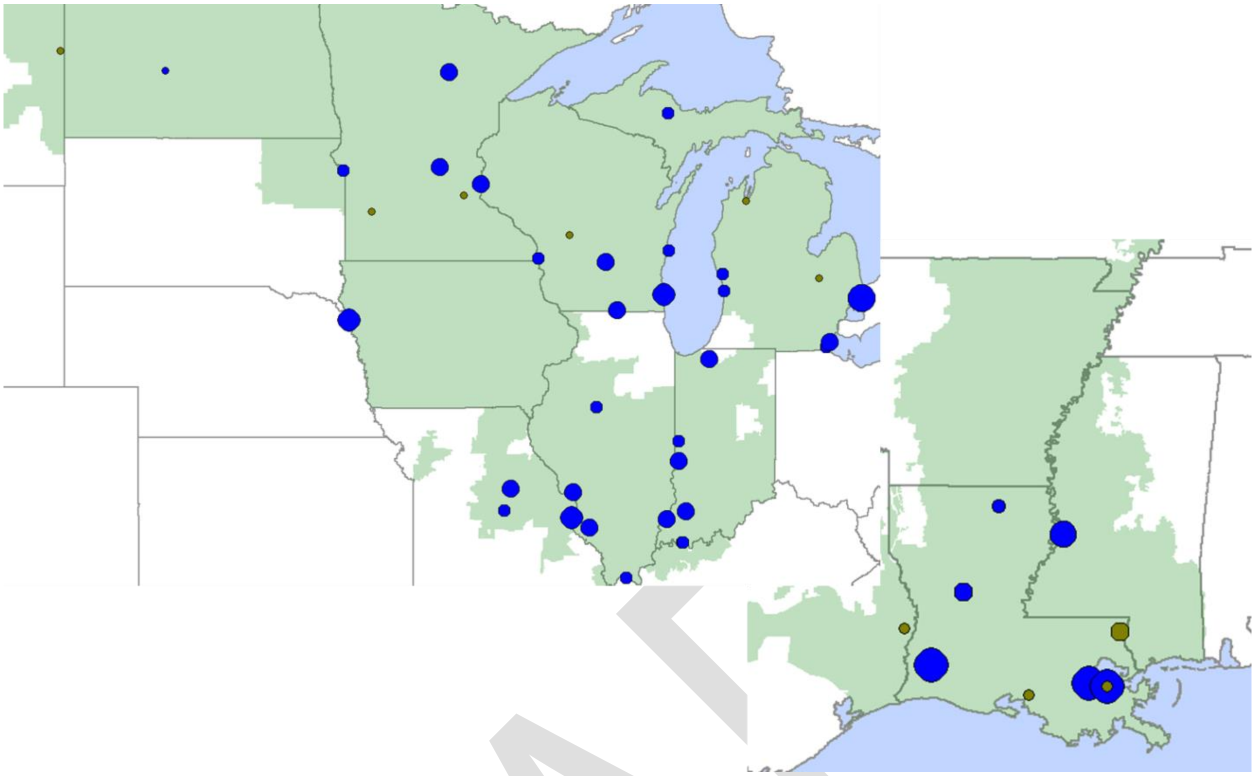


Figure 5.2-6: Accelerated Alternative Technology Future Siting (MapInfo)

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:

- WOTAB 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.

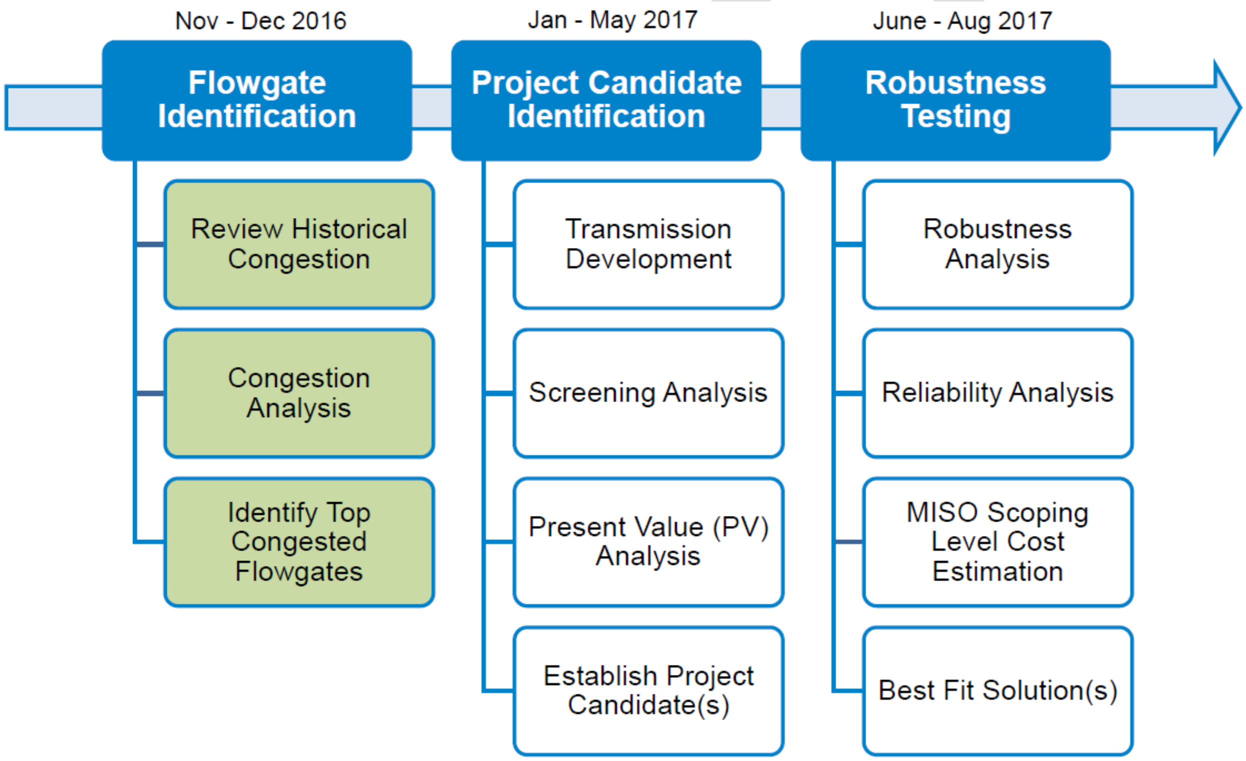


Figure 5.3-1: MCPS process overview

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

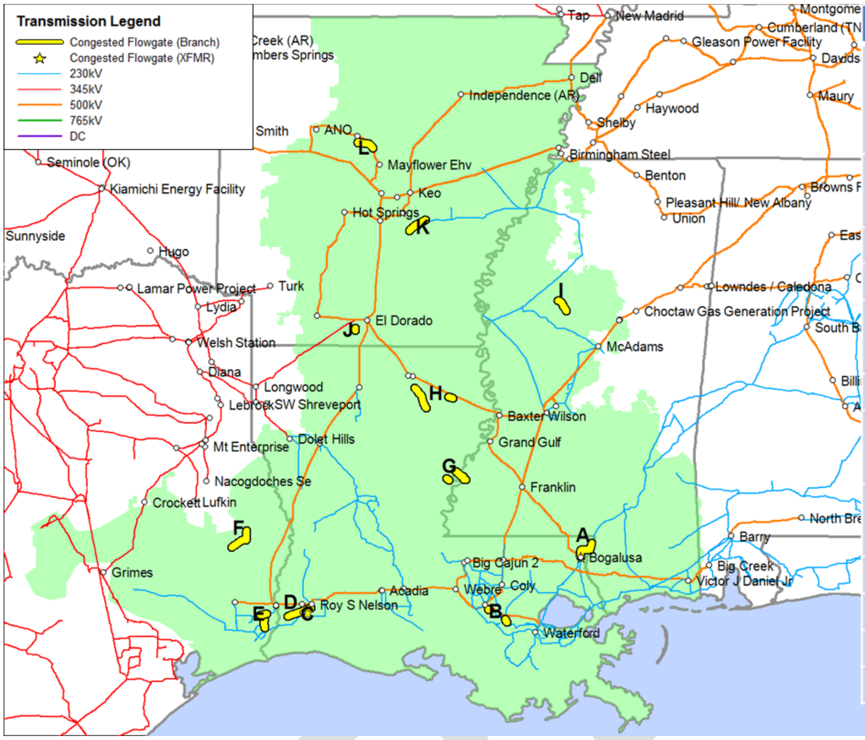
In Scenario 3, MISO utilized Entergy's issued generation request for proposals as a basis for siting future generation at Lewis Creek, Nelson and Michoud (Table 5.3-4).

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[33]
- Projected congestion identified through out-year production cost model simulations[34]

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.

[33] These flowgates include multiple element contingencies (e.g. generator + transmission line events)
[34] 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.[35]

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.[36]

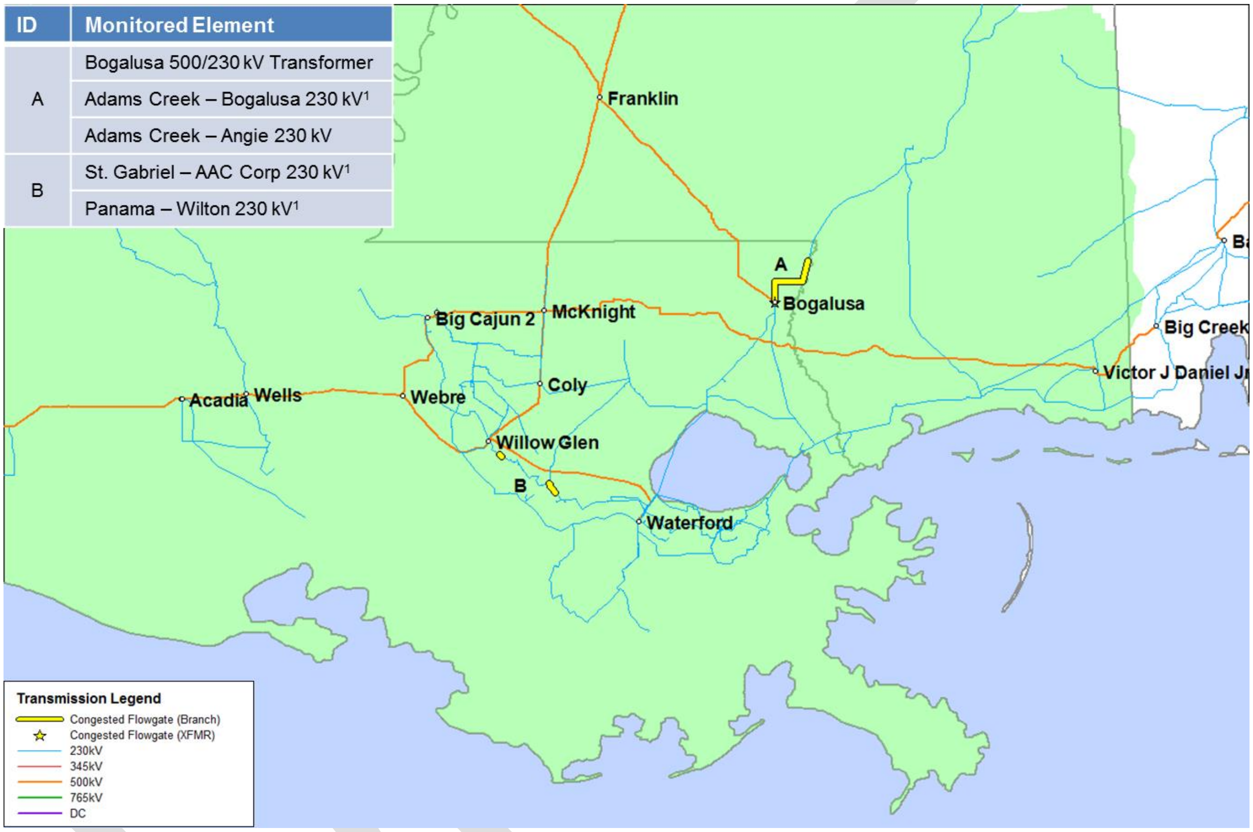


Figure 5.3-3: Amite South/DSG top congested flowgates

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.

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

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 and a generator is lost at the Sabine substation, flows shift to the remaining 230 kV network in the Sabine area.[37]

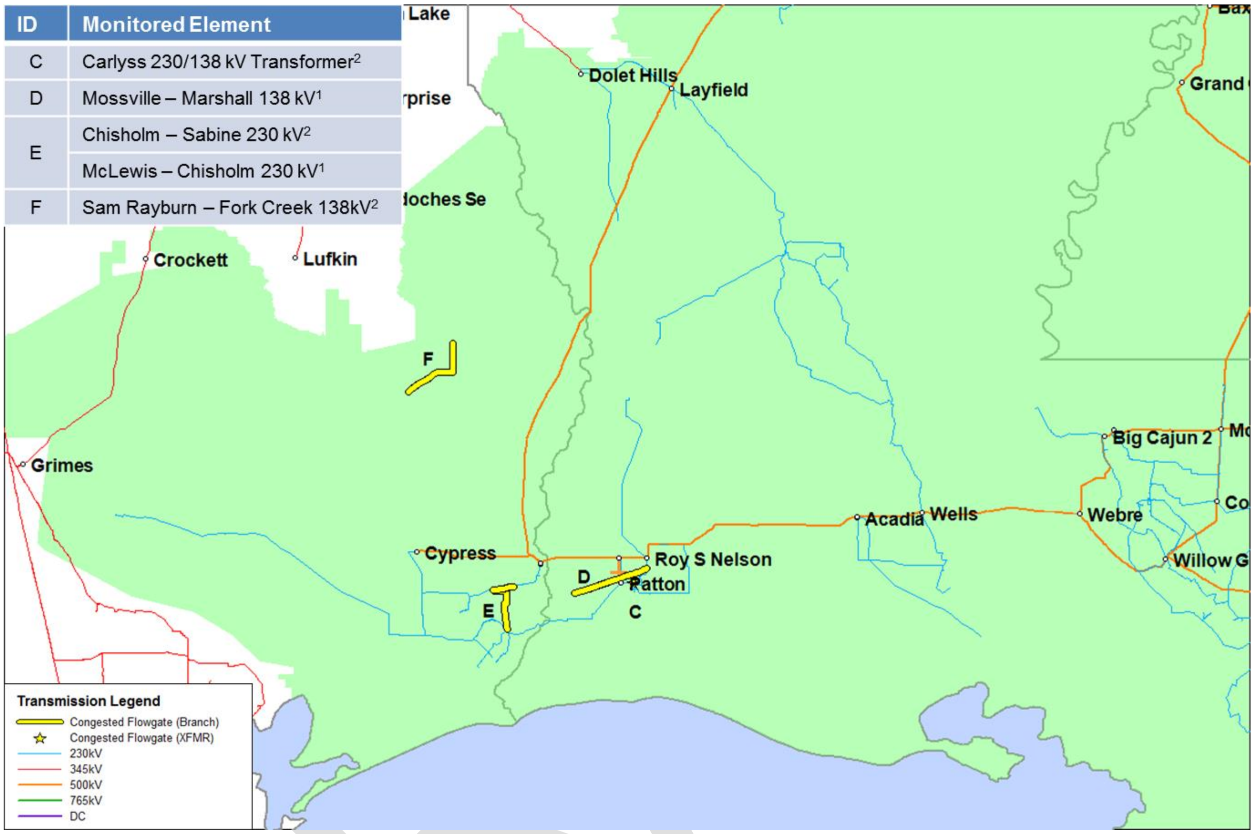


Figure 5.3-4: WOTAB/Western top congested flowgates

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.[38]

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-

[37] These flowgates include multiple element contingencies (e.g. generator + transmission line events)
[38] 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 WOTAB 500 kV Economic Project.

In the additional scenarios, the WOTAB Economic Project continued to perform well. Additionally, WOTAB 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 WOTAB 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 WOTAB 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.

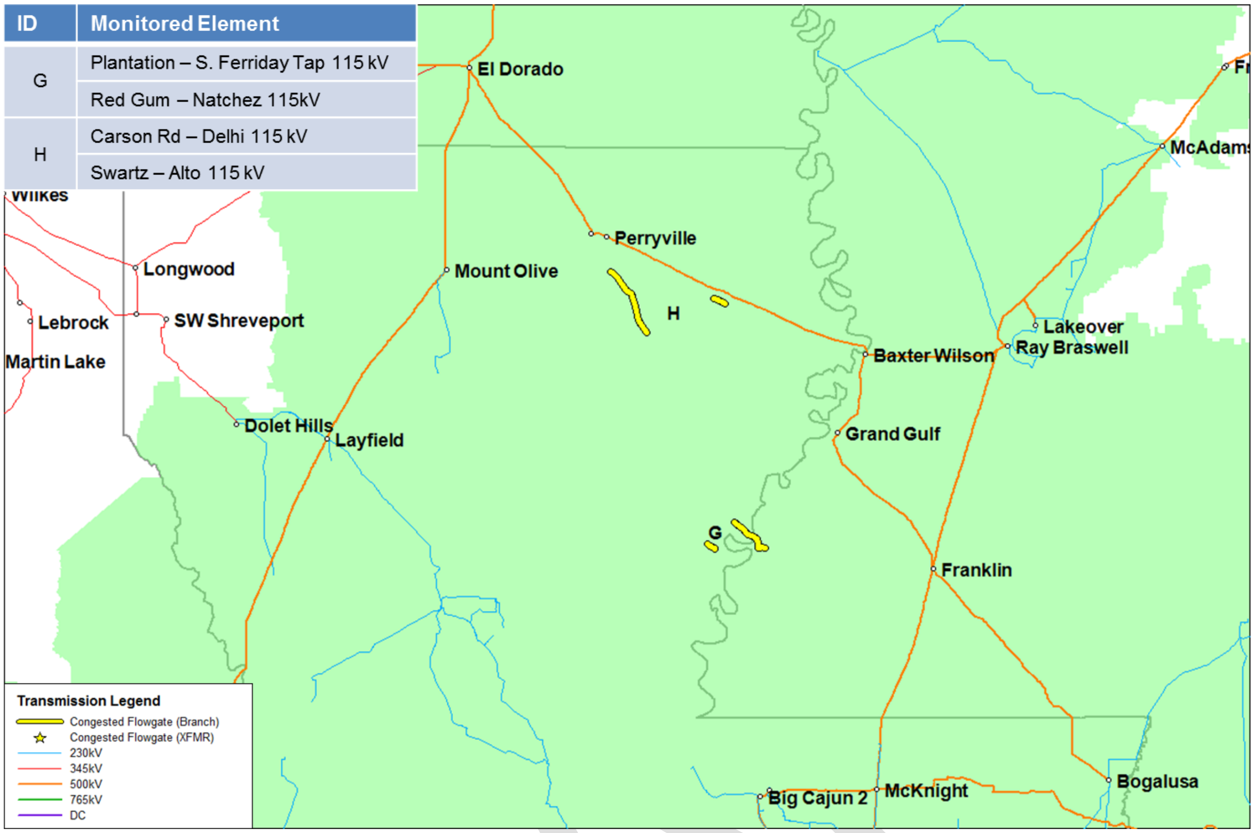


Figure 5.3-5: Remainder of LRZ9 (Rest of Louisiana) top congested flowgates

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.

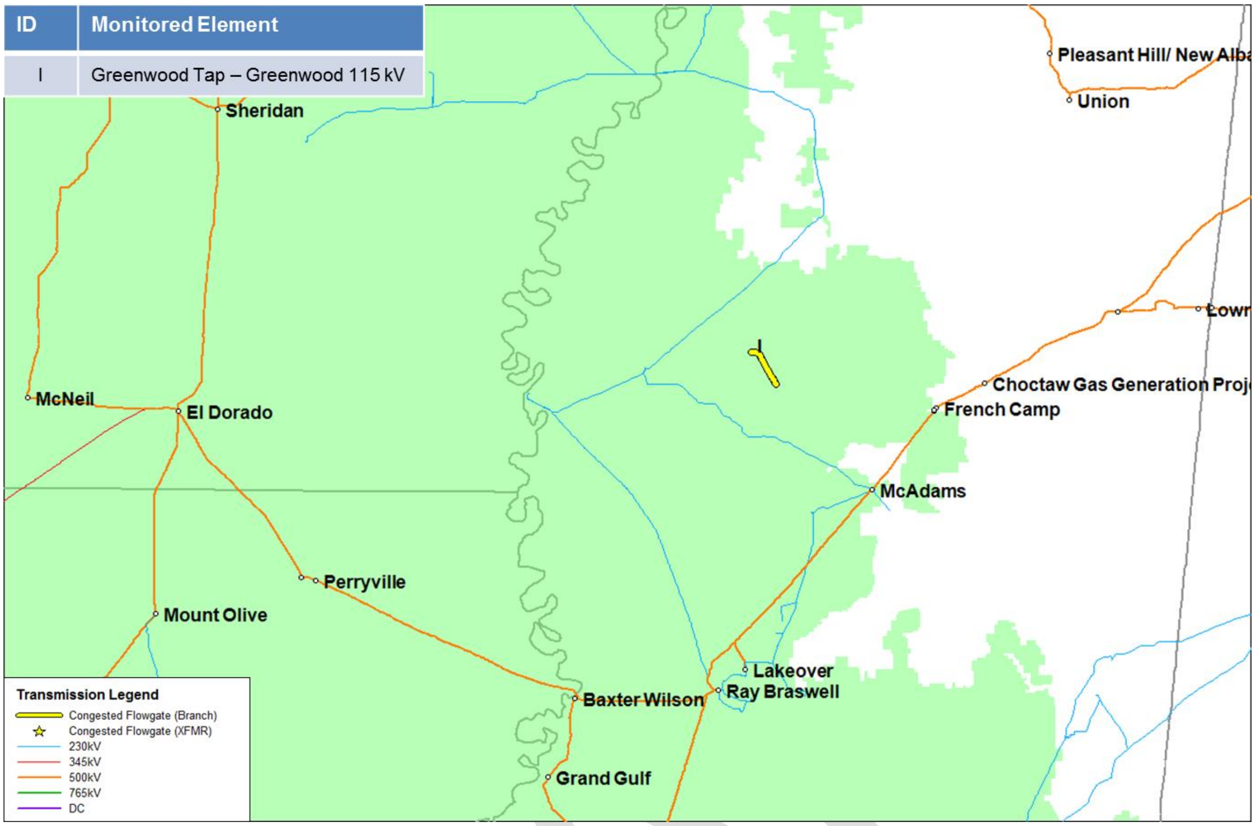


Figure 5.3-6: LRZ10 (Mississippi) top congested flowgates

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).

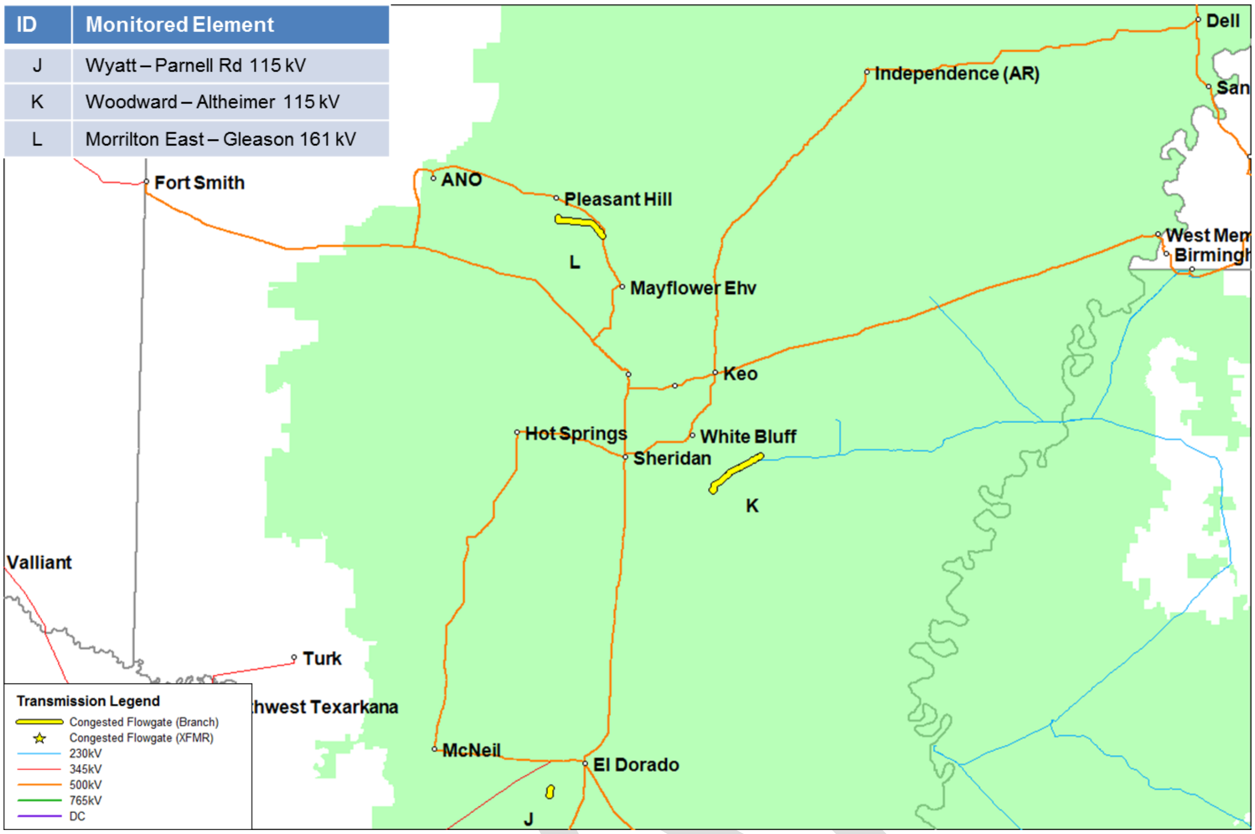


Figure 5.3-7: LRZ8 (Arkansas) top congested flowgates

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.

Book 2 / Resource Adequacy

Section 6: Resource Adequacy Intro and Enhancements

6.0 Resource Adequacy Introduction and Enhancements

MISO's ongoing goal is to support the achievement of Resource Adequacy — to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during peak times and at just, reasonable rates. The responsibility for Resource Adequacy does not lie with MISO, but rather rests with Load Serving Entities and the states that oversee them (as applicable by jurisdiction). Additional Resource Adequacy goals include maintaining confidence in the attainability of Resource Adequacy in all time horizons, building confidence in MISO's Resource Adequacy assessments and providing sufficient transparency and market mechanisms to mitigate potential shortfalls.

Five guiding principles provide the framework necessary to achieve these goals.

1. Resource Adequacy processes must ensure confidence in Resource Adequacy outcomes in all time horizons
2. MISO will work with stakeholders to ensure an effective and efficient Resource Adequacy construct with appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities
3. MISO will determine adequacy at the regional and zonal level and provide appropriate regional and zonal Resource Adequacy transparency and awareness for multiple forward time horizons
4. MISO will administer and evolve processes in a manner that provides transparency and reasonable certainty, appropriately protects individual market participant proprietary information in order to support efficient stakeholder resource and transmission investment decisions
5. MISO's resource planning auction and other processes will support multiple methods of achieving and demonstrating Resource Adequacy, including self-supply, bilateral contracting and market-based acquisition.

To date, the Resource Adequacy process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation (LOLE) analysis, the Planning Resource Auction, and the Organization of MISO States-MISO Survey. With the resource portfolio now evolving due to coal retirements and the increase in gas-fired generation, MISO is evaluating the Resource Adequacy requirements. This evaluation has led to an evaluation of the MISO processes, with focuses on:

- Aligning treatment of external and internal resources
- Ensuring LOLE assumptions align with Planning Resource Auction inputs
- Visibility into non-summer resource adequacy risk

6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM ICAP) for the 2017-2018 planning year, spanning from June 1, 2017, through May 31, 2018, is 15.8 percent, an increase of 0.6 percentage points from the 15.2 percent PRM set in the 2016-2017 planning year (Figure 6.1-1).

The PRM ICAP is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.6 percentage point PRM ICAP increase was the net effect of an increase in forced outage rates and reduction in load forecasts.

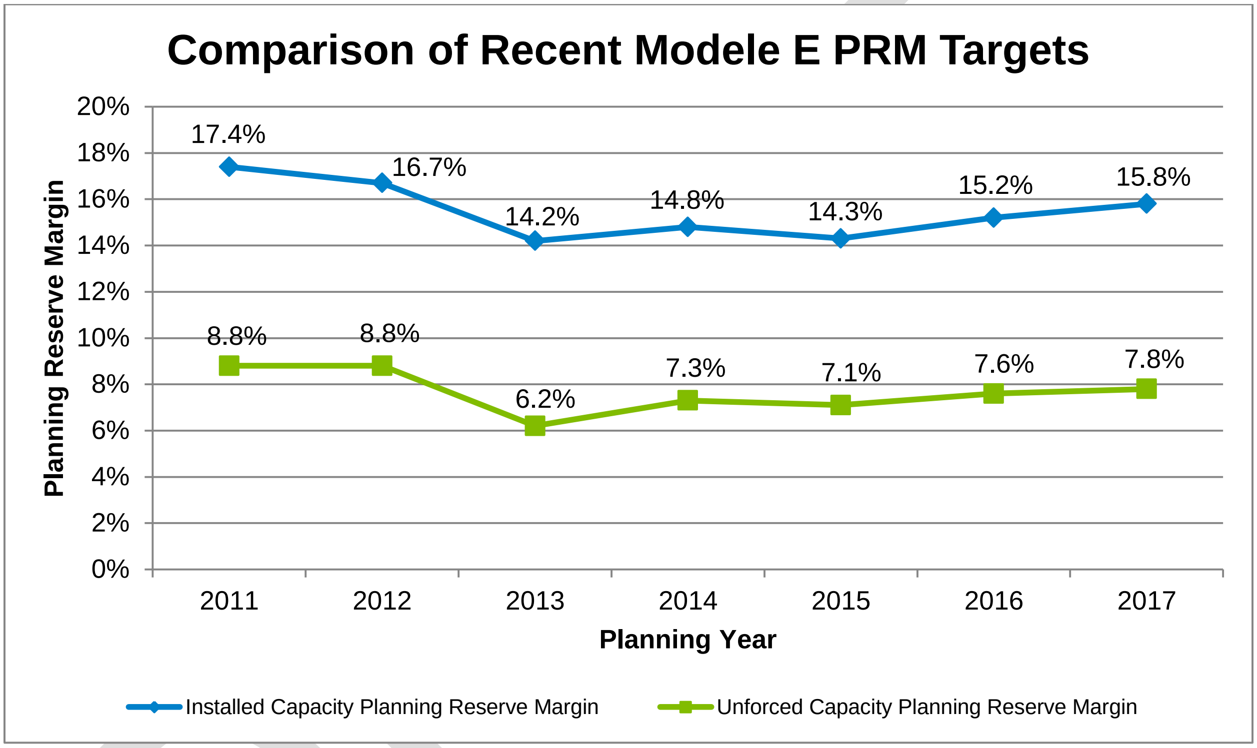


Figure 6.1-1: Comparison of recent PRM

As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate Planning Reserve Margin (PRM) for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study and the deliverables from the Loss of Load Expectation Working Group (LOLEWG) are based on the Resource Adequacy construct per Module E-1. MISO performs an annual LOLE study to determine the congestion-free PRM on an installed and unforced capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined for each

Local Resource Zone (LRZ) (Figure 6.1-2), which is defined as the amount of resources a particular area needs to meet the LOLE criteria of one day in 10 years without the benefit of importing capacity. These results are merged with the Capacity Import Limit (CIL), Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.

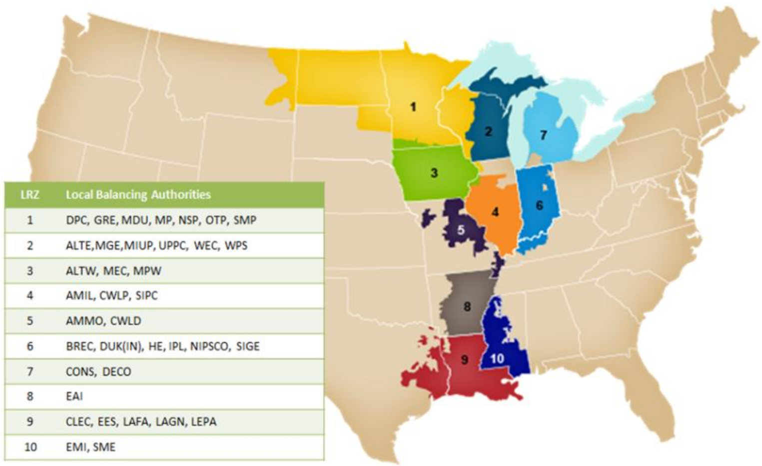


Figure 6.1-2: Local Resource Zones (LRZ)

2017-2018 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM UCAP, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1).

The PRM UCAP[39] increased from 7.6 percent in the 2016-2017 LOLE report to 7.8 percent in the 2017-2018 LOLE report due to the modeling parameter changes. More information on the increase is available in the 2017 LOLE report[40]. Under the existing construct, the PRM UCAP is applied to the peak of each Load Serving Entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). Adjustments were made to CIL based on a December 31, 2015 FERC order to reflect resources committed to non-MISO load. The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the resources cleared in the auction can be reliably delivered.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
LRR UCAP per-unit of LRZ Peak Demand	1.113	1.117	1.125	1.228	1.218	1.117	1.141	1.258	1.118	1.412
Capacity Import Limit (CIL) (MW)	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910
Capacity Export Limit (CEL) (MW)	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747

Table 6.1-1: Deliverables to the 2016-2017 Planning Resource Auction (PRA)

[39] PRM UCAP is the value accounting for the forced outage rate of capacity. More information on this calculation may be found in the LOLE report.
[40] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf

LRZ	Tier	17-18 Limit (MW)[41]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)[42]	Generation Redispatch (MW)	16-17 Limit (MW)
1	1	3,531	Point Beach to Kewaunee 345 kV	Fox River to North Appleton 345 kV	1	2,940	2,000	3,436
2	1	2,227	Stoneman to Nelson Dewey 161 kV	Seneca to Genoa 161 kV	2	553	2,000	1,609
3	1	2,408	Sub 3458 to Sub 3456 345 kV	Sub 3455 to Sub 3740 345 kV	3	1,876	550	1,886
4	1 & 2	5,815	Meredosia to Jacksonville Industrial Park 138 kV	Ballard – Meredosia 138 kV	4	3,658	0	6,323
5	1	4,096	Sikeston to Idalia 161 kV	Essex – New Madrid 345 kV	5	2,559	1,689	4,837
6	1 & 2	6,248	Cayuga – Cayuga sub 345 kV	Rockport to Jefferson 765 kV	6	N/A		5,610
7	N/A	3,320	Brownstown 345 kV Bus	Monroe – Wayne 345 kV	7	N/A		3,521
8	1	3,275	Colonial Orange to Cow 138 kV	Sabine to Cow 500 kV: 138 kV	8	2,340	826	3,527
9	1	3,371	Bogalusa 500/230 kV	McKnight to Franklin 500 kV	9	2,169	1,756	4,490
10	1	1,910	Freeport to Twinkletown 230 kV	Freeport to Horn Lake 230 kV	10	1,594	1,984	2,653

Table 6.1-2: 2017-2018 Planning Year Capacity Import Limits

[41] The 17-18 Limit represents the limit after redispatch has been considered
[42] The Initial Limit represents the limit before considering redispatch.

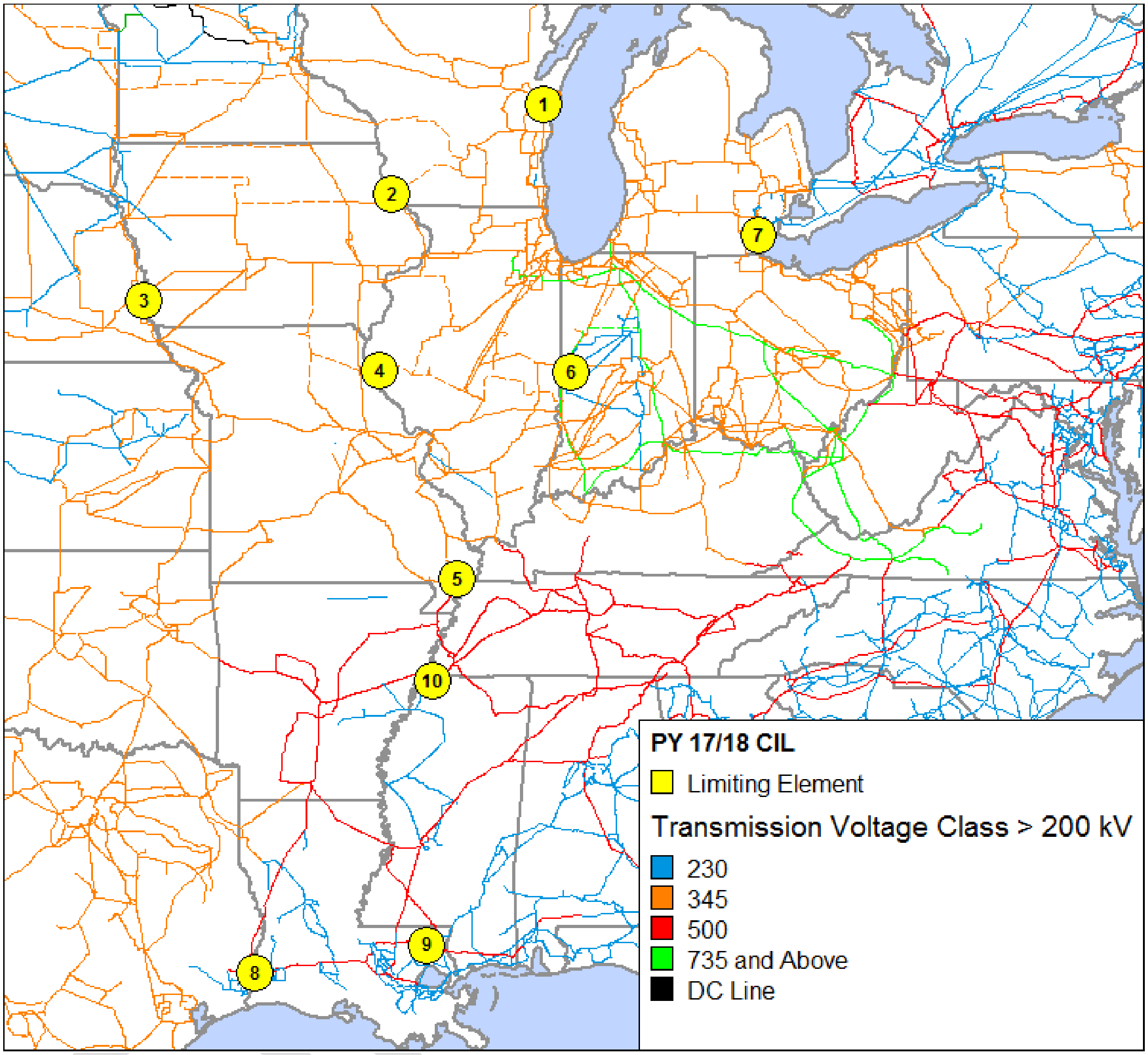


Figure 6.1-3: 2017-2018 Capacity Import Limit map

LRZ	17-18 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	Initial Limit (MW)	Generation Redispatch (MW)	16-17 Limit (MW)
1	686	Lakefield to Dickinson 161 kV	Lakefield to Obrien 345 kV	1	0	1,674	590
2	2,290	Sherman Street to Sunny Vale 115 kV	Arpin to Rocky Run 345 kV	2	N/A		2,996
3	1,772	Colby to Northern Iowa Wind 161 kV	Adams to Barton 161 kV	3	497	1,362	1,598
4	11,756	No transmission constraint identified	N/A	4	N/A		7,379
5	2,379	Peno Creek to Marion Tap 161 kV	Maywood to Spencer Creek 345 kV	5	N/A		896
6	3,191	Stout CT to Southwest 138 kV	Stout North to Stout CT 138 kV	6	N/A		2,544
7	2,519[43]	Custer to Whiting 120 kV	Lulu – Morocco – Milan 345 kV	7	N/A		4,541
8	2,493	Catherine to Arklahoma 115 kV	Base Case	8	2,289	1,126	2,074
9	2,373	Cow to Colonial Orange 138 kV	Sabine to Cow 500 kV	9	1,422	1,686	1,261
10	1,747	Batesville to Tallahatchie 230/115 kV	Choctaw to Clay 500 kV	10	890	1,540	1,857

Table 6.1-3: 2017-2018 Planning Year Capacity Export Limits

[43] Rating of limiting element increased since initiation of LOLE study. Limit reflects export capability considering new rating identified after completion of LOLE study prior to the auction.

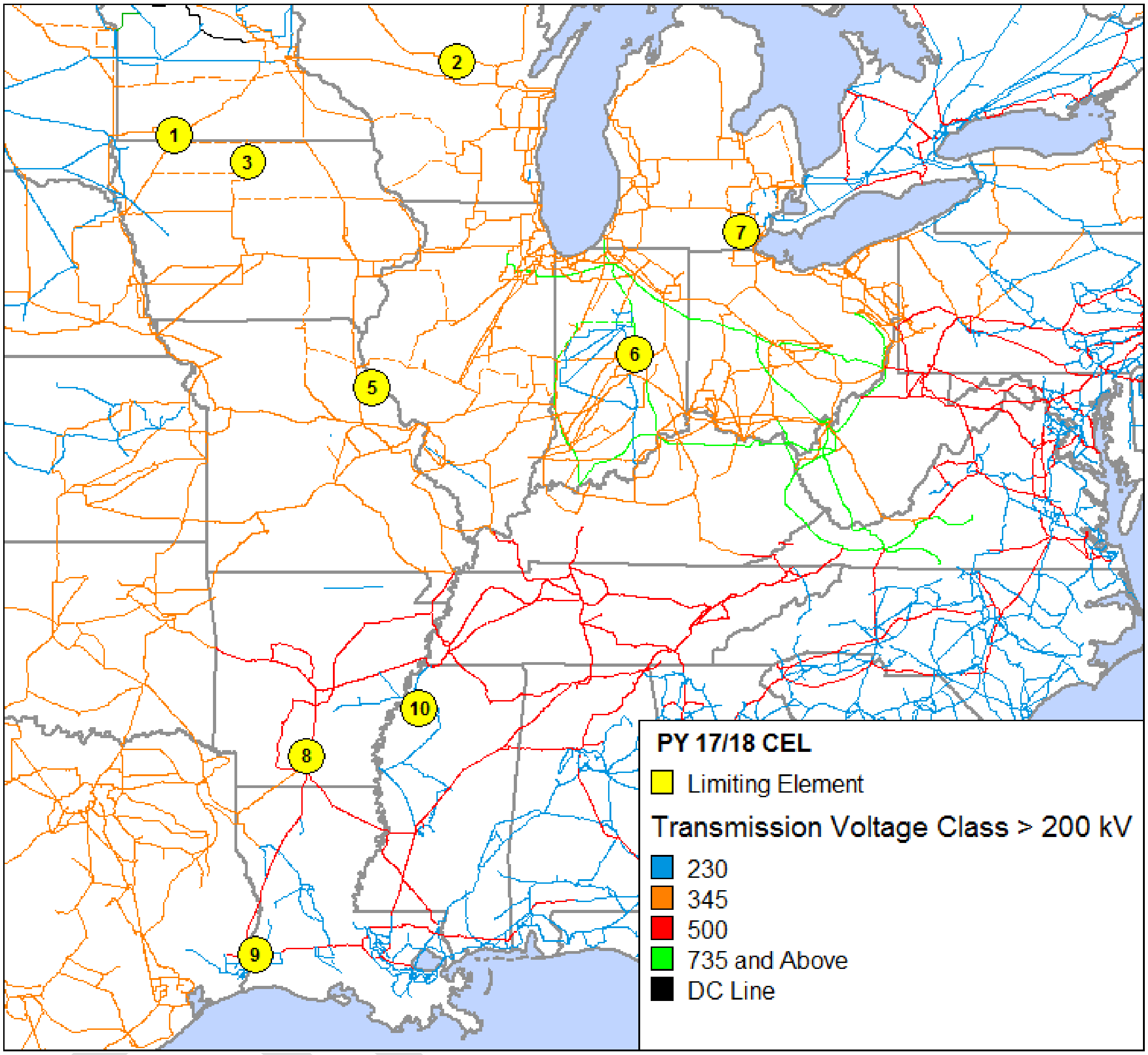


Figure 6.1-4: 2017-2018 Capacity Export Limit map

MTEP Projects and Capacity Import and Export Limits

The Capacity Import and Export Limits are deliverables to the Planning Resource Auction (PRA) and, in combination with the Local Clearing Requirement (LCR), determine the maximum amount of imports or exports allowed for a zone. Constraints may occur in the PRA when the imports or exports are limited by the CIL, CEL, and LCR. These constraints are considered in the development of the MTEP. Table 6.1-4 outlines projects impacting LCR, CIL or CEL that impact limits that have bound in the previous two Planning Resource Auctions.

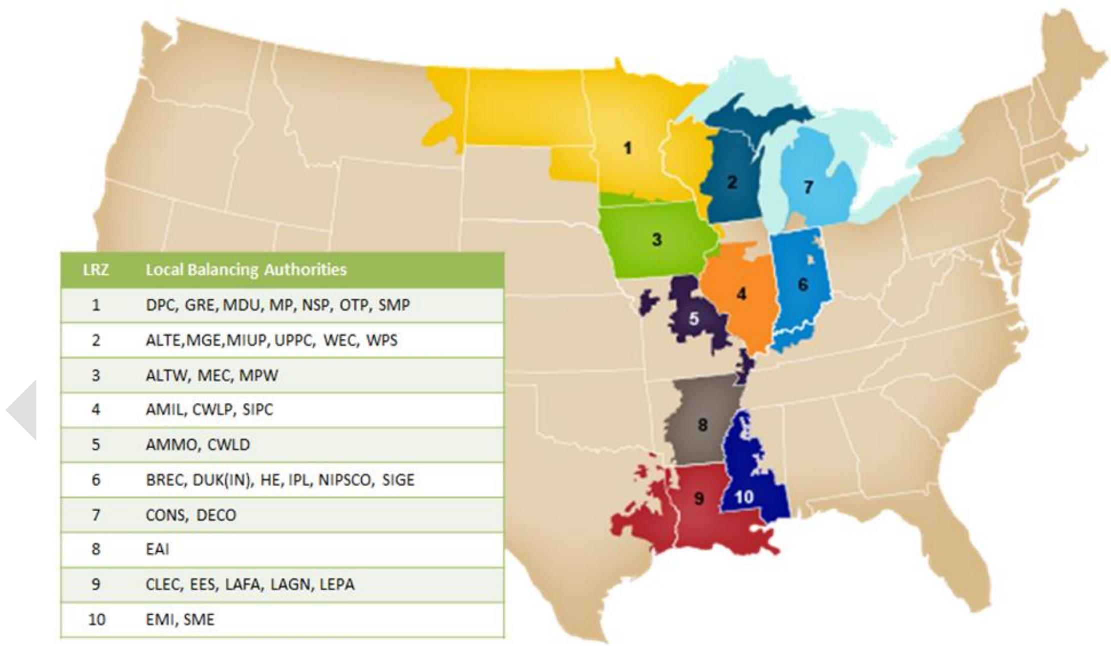
LRZ	CEL or CEL	Monitored Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
1	CEL	Lakefield to Dickinson 161 kV Line	3205, 3213	A in MTEP11	Proposed MVP Portfolio 1: Lakefield Jct. – Winnebago – Winco – Kossuth County and Obrien County – Kossuth County – Webster 345 kV line and Proposed MVP Portfolio 1 – Winco to Hazleton 345 KV line	9/28/2015 – 6/1/2018, 6/1/2015 – 12/31/2018

Table 6.1-4: MTEP project impacting CEL which has bound in the PRA

For full details of the LOLE study, refer to the Planning Year 2017 LOLE study report.

Wind Capacity Credit

A class-average wind capacity credit of 15.6 percent was established for the 2017-2018 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit remained the same from the wind capacity credit of 15.6 percent established in the 2016-2017 Planning Year (Figure 6.1-5). For more information, refer to the complete 2017 Wind Capacity Credit Report[44].



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	15,910	4,703	636	7,853	644	282	1,792	0	0	0
UCAP (MW)	2,482	861	88	1,214	67	25	226	0	0	0
ELCC %	15.6%	18.3%	13.9%	15.5%	10.5%	8.8%	12.6%	0.0%	0.0%	0.0%
Wind CPnode Count	204	72	10	84	8	4	26	0	0	0

Figure 6.1-5: Wind Capacity Credit by Local Resource Zones (LRZ) for 2017-2018 Planning Year

[44] Or: https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20Wind%20Capacity%20Report.pdf

Solar Capacity Credit

A class-average solar capacity credit of 50 percent was established for the 2017-2018 planning year by estimating the peak period contribution from historical solar irradiance simulation data. New resources without summer operating history will receive this class average capacity credit until at least 30 consecutive days of summer performance data are available, at which time the resource's individual capacity credit will be based on its own operating history. More details can be found in the MISO BPM-011 in section 4.

6.2 Long-Term Resource Assessment

The Long-Term Resource Assessment (LTRA) examines the balance between projected resources and the projected load. These resources are compared with Planning Reserve Margin Requirements (PRMR) to calculate a projected surplus or shortfall.

MISO forecasts sufficient capacity resources to meet expected demand and reserves for the next five years, above the Planning Reserve Margin Requirement (PRMR) of 15.8 percent. Beginning in 2023 MISO capacity is projected to fall below the PRMR and remain there for the rest of the assessment period (Table 6.2-1). Falling below the PRMR signifies that the MISO region is projected to operate at a reliability level lower than the one-day-in-10 standard in 2023 and beyond. The LTRA results represent a point in time forecast, and MISO anticipates the projected margins will change significantly as Load Serving Entities and state commissions solidify future capacity plans.

This is an expected result, as 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need (CPCN).

In GW (ICAP)	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28
(+) Existing Resources	150.0	149.3	148.9	148.6	146.7	145.0	144.7	144.2	144.0	144.0
(+) New Resources	2.0	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5
(+) Imports	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.1	3.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
(-) Low Certainty Resources	1.0	1.1	1.4	1.5	1.5	2.3	2.3	2.4	2.4	2.4
(-) Transfer Limited	2.5	2.3	2.1	1.8	1.1	0.0	0.0	0.0	0.0	0.0
Available Resources	148.5	150.4	150.3	150.4	149.2	147.8	147.5	147.0	146.8	146.8
Demand	125.9	126.5	127.0	127.6	128.3	128.9	129.4	129.1	128.9	128.9
PRMR	145.8	146.5	147.1	147.8	148.5	149.2	149.9	149.5	149.3	149.3
PRMR Surplus / Shortfall	2.7	3.9	3.2	2.6	0.6	-1.4	-2.4	-2.5	-2.5	-2.5
Reserve Margin Percent (%)	17.9%	18.9%	18.3%	17.9%	16.3%	14.7%	14.0%	13.9%	13.8%	13.8%

Table 6.2-1: MISO projected PRMR details (cumulative)

MISO projects a regional surplus for the summer of 2018, and continuing on through the summer of 2022. These results show a regional surplus instead of the deficit from the 2016 MISO LTRA results, including uncommitted resources.

Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in the use of Load Modifying Resources (LMR), such as Behind-the-Meter Generation (BTMG) and Demand Response (DR).

In 2018, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak.

The conclusions from the long-term resource assessments are:

- An increase in resources committed to serving MISO load mainly by independent power producers (IPP).
- Lower demand-growth forecasts across most zones in MISO.
- The increase in committed resources from BTMG and Demand Response.
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their Local Clearing Requirements, or the amount of their local resource requirement, which must be contained within their boundaries.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; also MISO is engaged with stakeholders in a number of Resource Adequacy reforms to help rectify these out year shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the reserve margin requirement.

Assumptions

At the end of 2013 MISO and Organization of MISO States (OMS) conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the fourth iteration of the OMS-MISO survey in June 2017, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2018, MISO anticipates that the MISO Region’s coincident demand will be 125,921 MW, which is a 50/50 weather-normalized load forecast.

Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.3 percent for the period from 2018 to 2028.

In 2018, MISO anticipates that the MISO Region’s coincident demand will be 125,921 MW, which is a 50/50 weather-normalized load forecast.

Resources

In 2018, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak.

MISO’s current generation capacity (nameplate) of 174,724 MW steps down to Existing-Certain Capacity Resources of 139,200 MW by accounting for summer on-peak generator performance (including wind capacity at 15.6 percent of nameplate and solar at 50 percent of nameplate), transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 139,200 MW towards its PRMR to meet a loss-of-load expectation of one day in 10 years.

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO’s Emergency

Operating Procedures. MISO assumes the 4,129 MW of BTMG increasing to 4,169 in 2022 and 5,620 MW of LMR DR that was qualified in the 2017 Planning Resource Auction to be available throughout the assessment period.

In the 2017 MISO-OMS survey, resources that were identified to have a low certainty of serving load were not included (Figure 6.2-1).

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 4,517 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period (Figure 6.2-1). This is based on a snapshot of the GIQ as of June 2017 and is the aggregation of active projects with a signed Interconnection Agreement.

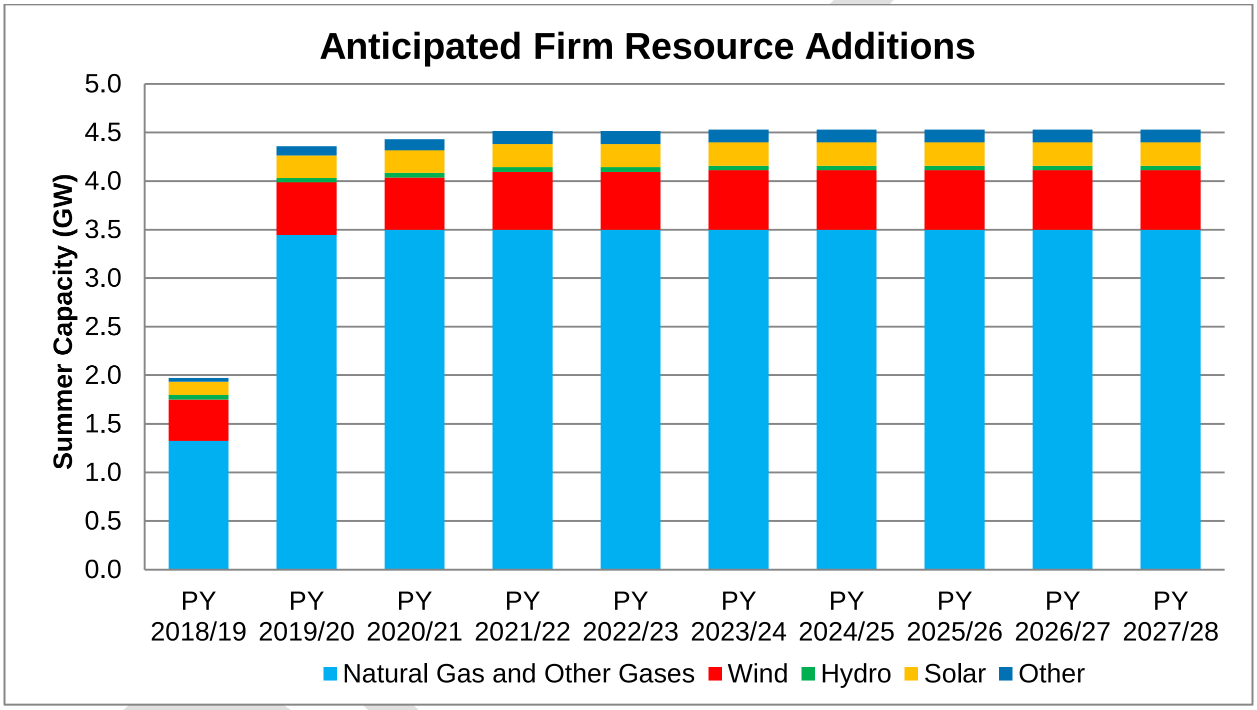


Figure 6.2-1: Anticipated Resource Additions and Uprates (Cumulative) of active projects with a signed Interconnection Agreement in the MISO Region

Imports and Exports

MISO assumes a forecast of 4,106 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider. This capacity was designated to serve load within MISO through the Module E process for summer 2018. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 4,134.7 MW of firm capacity exports in year 2018. Exports are projected to decrease to 3,600 MW in 2020 and remain at that level for the rest of the assessment period.

When comparing reserve margin percent numbers between Figure 6.2-1 and the NERC LTRA, the percent for each planning year will be slightly lower in the NERC LTRA because of differences in the reserve margin percent calculation. MISO's resource adequacy construct counts DR as a resource while the NERC calculates DR on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is comparable between the two.

6.3 Seasonal Resource Assessment

MISO conducts seasonal resource assessments for the winter months of December, January and February as well as for summer months of June, July and August. Seasonal assessments primarily evaluate the expected near-term system performance and prepare operators for the upcoming season. The MISO resource assessments coincide with NERC seasonal reliability assessments and MISO operational readiness workshops held prior to the assessment's season.

The 2016-2017 winter and 2017 summer season findings show that the projected capacity levels exceed the Planning Reserve Margin Requirement, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with expected dispatch limits, only 1,500 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios for the 2017 Summer Assessment.

MISO coordinates extensively with neighboring Reliability Coordinators as part of the seasonal assessment and outage coordination processes, via scheduled daily conference calls and ad-hoc communications as need arises in real-time operations. There is always the potential for a combination of higher loads, higher forced outage rates and fuel limitations. In the summer, unusually hot and dry weather can lead to low water levels and/or high water temperatures. This can impact the maximum operating capacity of thermal generators that rely on water resources for cooling, leading to added deratings in real time and lowering functional capacity. MISO resolves these situations through existing procedures depending on the circumstances, and several scenarios are studied for each season to project the possible reserve margins expected.

Demand

Based on 21 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2017 LOLE Study.

Demand Reporting

MISO does not forecast load for the Seasonal Resource Assessments. Instead, Load Serving Entities (LSEs) report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO Tariff. LSEs report their annual load projections on a MISO Coincident basis as well as their Non-Coincident load projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. MISO LSEs have the best information of their load; therefore, MISO relies on them for load forecast information.

For these studies, MISO created a Non-Coincident and a Coincident peak demand on a regional basis by summing the annual peak forecasts for the individual LSEs in the larger regional area of interest.

2016-2017 Winter Overview

For planning year 2016-2017, MISO's Planning Reserve Margin Requirement (PRMR) was 15.2 percent. For the 2016-2017 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 35.4 percent, which far exceeds the PRMR of 15.2 percent. The winter scenarios project the reserve margin to be in the range of 28.4 to 37.5 percent (Figure 6.3-1).

MISO's 50/50 coincident peak demand for the 2016-2017 winter season was forecasted to be 103,973 MW including transmission losses, with 140,774 MW of capacity to serve MISO load during the 2016-2017 winter season. Excluded from the capacity are 6,110 MW of MISO South resources to align with the Planning Resource Auction (PRA) Sub-Regional Export Constraint (SREC).

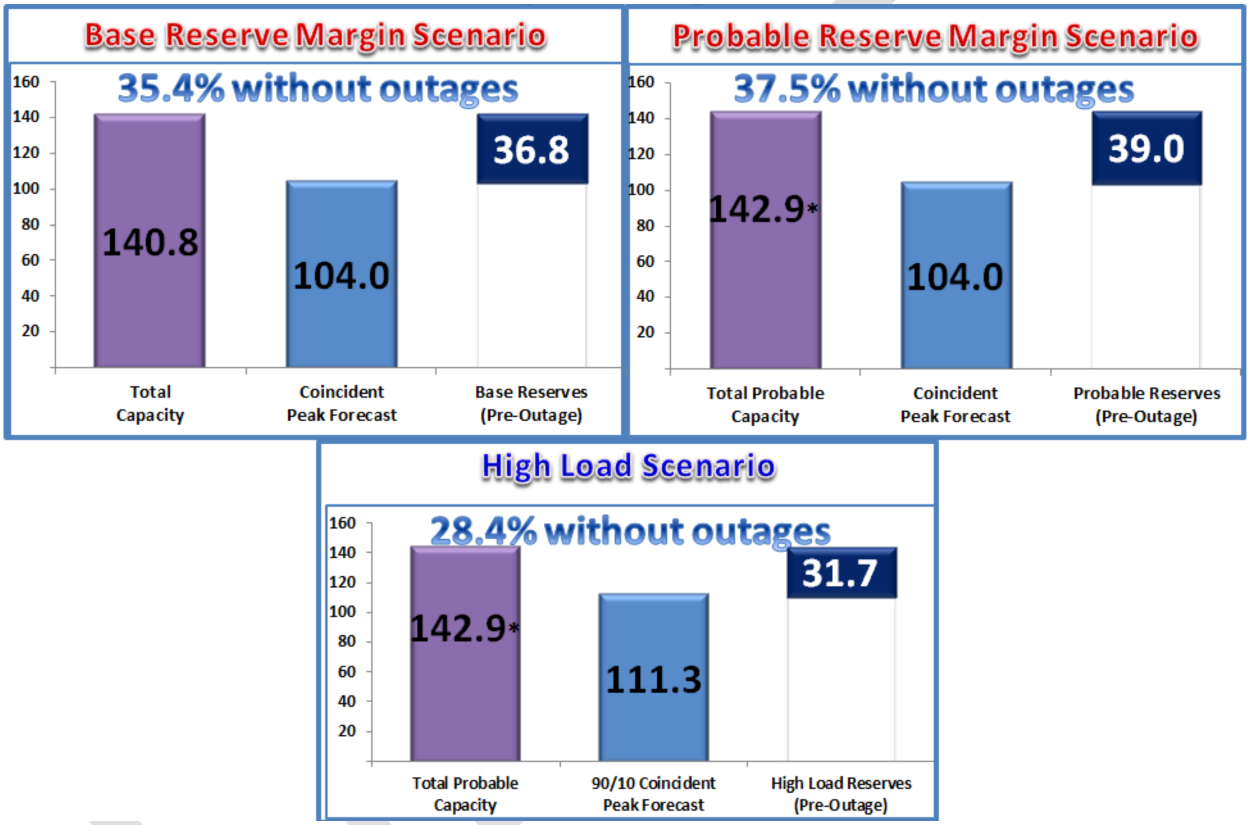


Figure 6.3-1: Winter 2016-2017 Projected Reserve Margin scenarios (GW)

2016-2017 Winter Rated Capacity

For the 2016-2017 winter season, MISO projected 140,774 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 2,255 MW of Behind-the-Meter Generation (BTMG) and 3,420 MW of Demand Resource (DR) programs, with 1,359 MW of Net Firm Exports. MISO expected 2,017 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 5,092 MW; thermal unit winter output reductions of 5,143 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 13,419 MW based on available nameplate wind resources of 16,041 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 876 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

Winter Reserve Margin Scenarios

MISO's projected 2016-2017 MISO Winter Rated Capacity varies by scenario (Figures 6.3-2 through 6.3-6). MISO chose the 90^{th} percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 111,273 MW for the 2016-2017 winter.

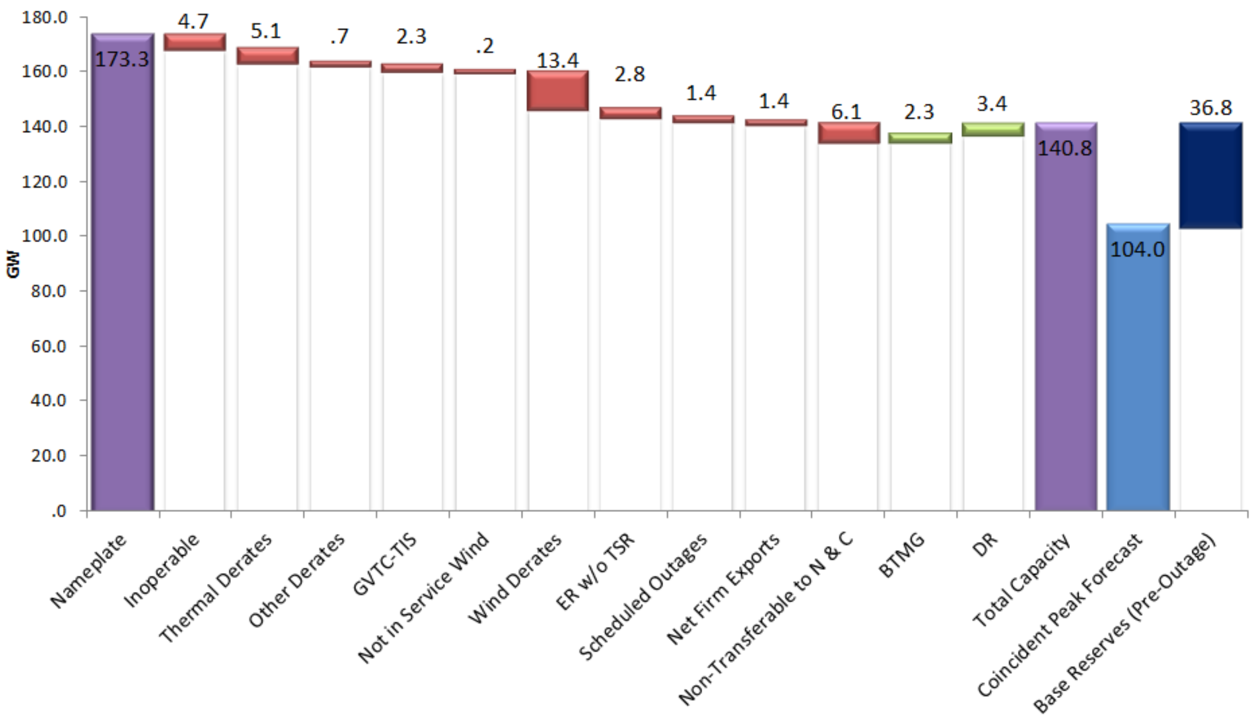


Figure 6.3-2: 2016-2017 Winter Rated Capacity projected Base scenario (GW)

The anticipated scenario contains additional assumptions (Figure 6.3-3). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 876 MW contract path limitation for the 2016-17 Planning Year.

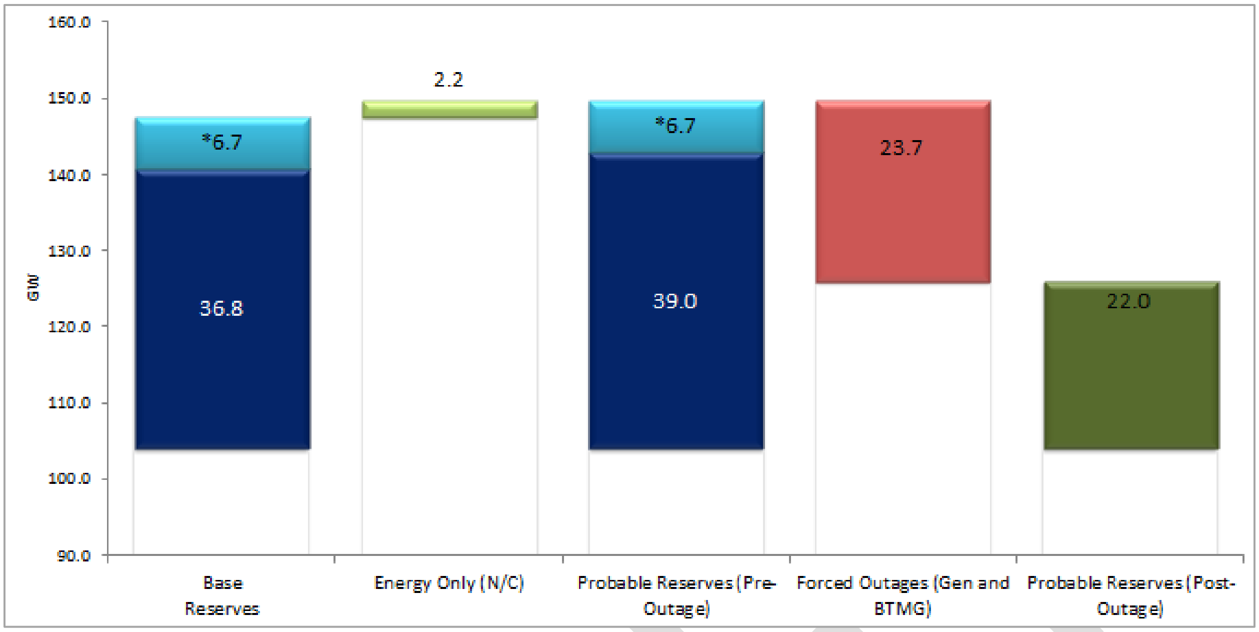


Figure 6.3-3: 2016-2017 Winter Rated Capacity projected Anticipated scenario (GW)
*Stranded South capacity is added to reserves to reflect outages seen by operations

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2016-2017 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

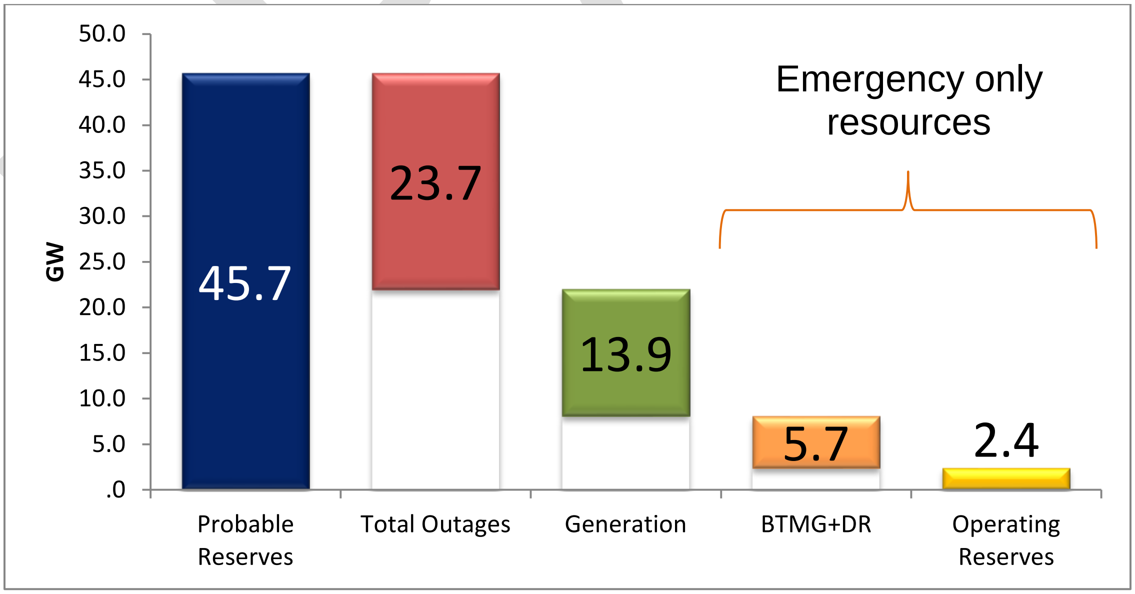


Figure 6.3-4: 2015-2016 Winter Rated Capacity projected anticipated scenario reserves (GW). Trapped South capacity is included in the probable reserves.

The High Demand, High Outage scenario has added assumptions (Figure 6.3-5). Beginning with the anticipated reserves from the Probable scenario (Figure 6.3-3), the load increases to show the higher load from a 90/10 forecast. Higher than normal outages are assumed reflecting the highest seasonal average outages reported in GADS from 2011-2015. The extreme outages reflect the highest number of GADS reported outages seen on winter peak from 2011-2015.

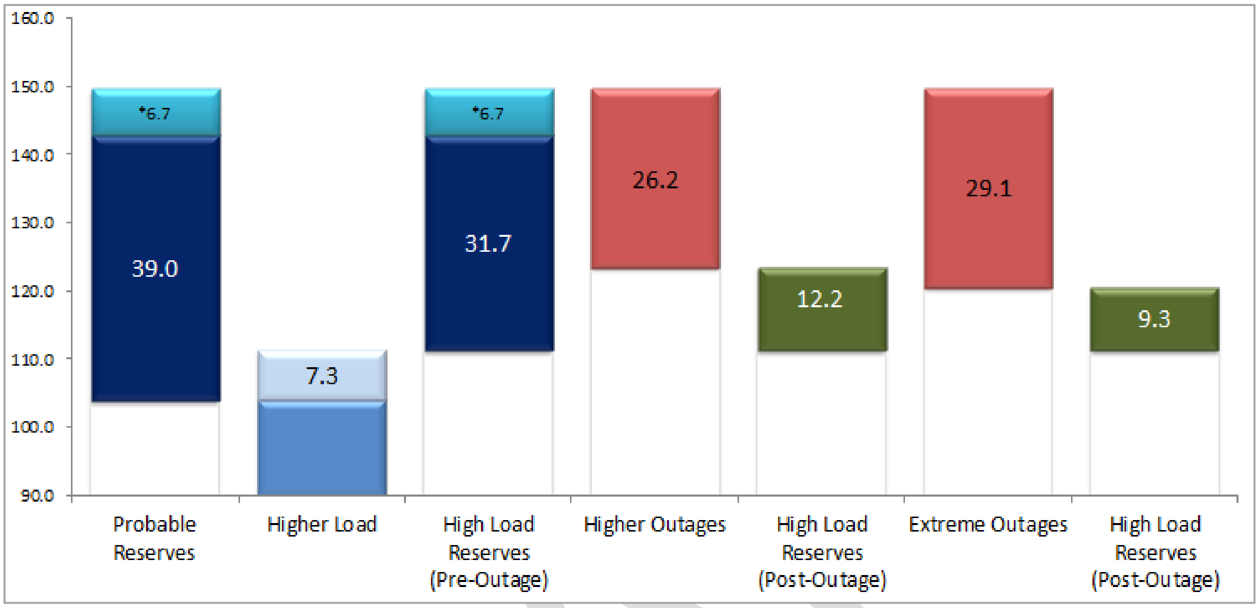


Figure 6.3-5: Winter Rated Capacity projected High-Demand, High-Outage scenario (GW)
*Stranded South capacity is added to reserves to reflect outages seen by operations

2017 Summer Overview

For planning year 2017-2018, MISO's PRM is 15.8 percent. During the 2017 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 18.8 percent, which exceeds the requirement of 15.8 percent by 3.0 percentage points. The summer scenarios project the reserve margin to be in the range of 14.1 to 19.7 percent (Figure 6.3-7).

MISO's 50/50 coincident peak demand for the 2017 summer season was forecasted to be 125,002 MW including transmission losses, with 148,465 MW of capacity to serve MISO load. Excluded from the capacity are 1,134 MW of MISO South resources to align with the 1,500 MW intra-RTO contract path.

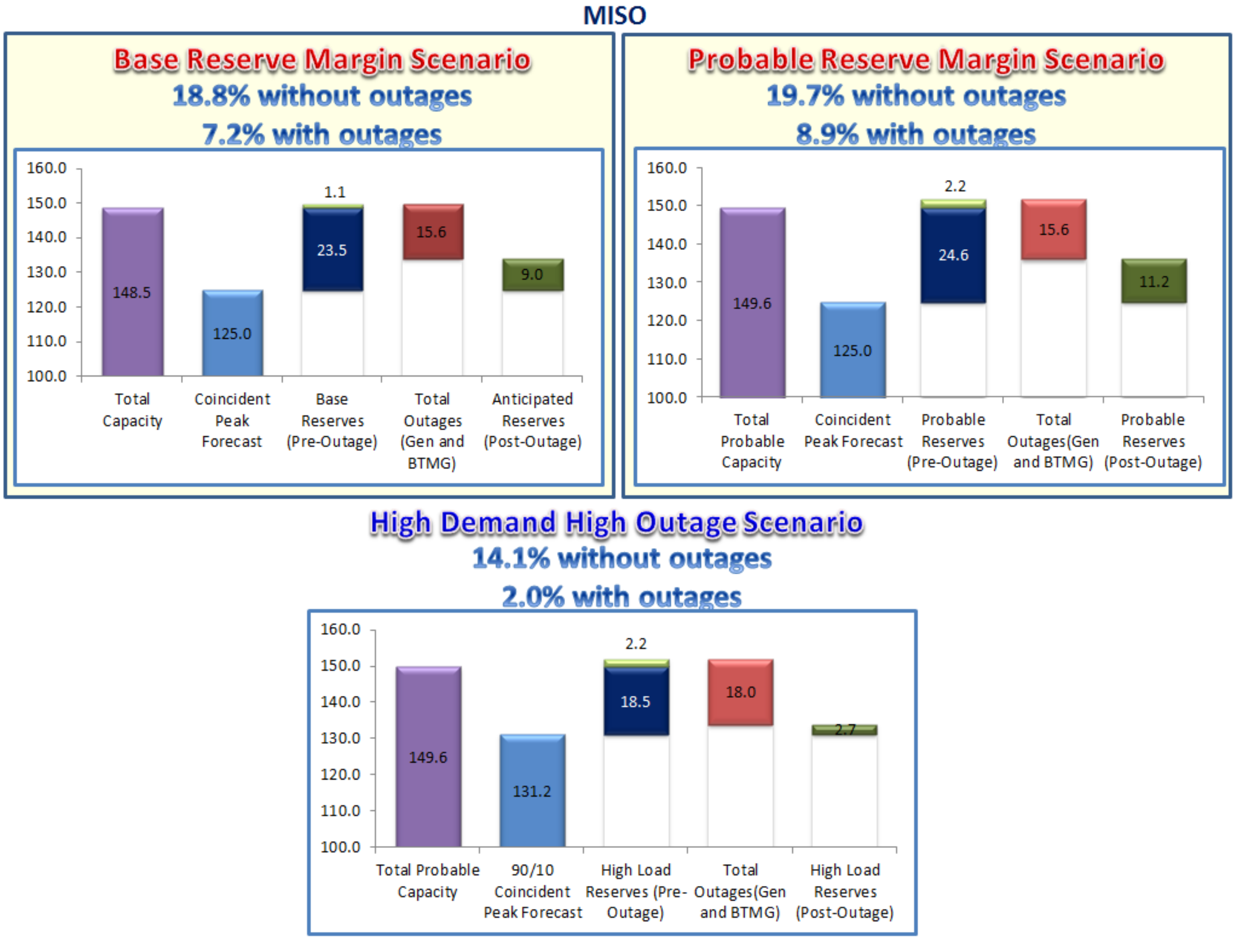


Figure 6.3-6: Summer 2017 Projected Reserve Margin scenarios

2017 Summer Rated Capacity

For 2017, MISO projected 148,465 MW of capacity to serve MISO load during the 2017 summer season. The capacity includes 4,059 MW of BTMG and 6,112 MW of DR programs, while including 45 MW of Net Firm Exports. MISO expected 2,281 MW of wind capacity to be available to serve load this summer, after discounting wind capacity in the Commercial Model with pending interconnection agreements and capacity with Energy Resource Interconnection Service without a firm point-to-point Transmission Service Request. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, 1,500 MW of excess capacity was assumed as transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (903 MW); thermal unit summer output reductions (9,601 MW); and reductions due to the Effective Load Carrying Capability of wind resources (13,241 MW). Also, any MISO South capacity over the total of South Load, South reserve margin requirement, and 1,500 MW of contract path was not included in the regional value. This means that 1,134 MW of MISO South excess capacity was excluded from the calculation to align with 1,500 MW contract path limitation.

Reserve Margin Scenarios

MISO's projected 2017 MISO Summer Rated Capacity varies by scenario (Figures 6.3-7 through 6.3-9). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 131,151 MW for the 2017 summer.

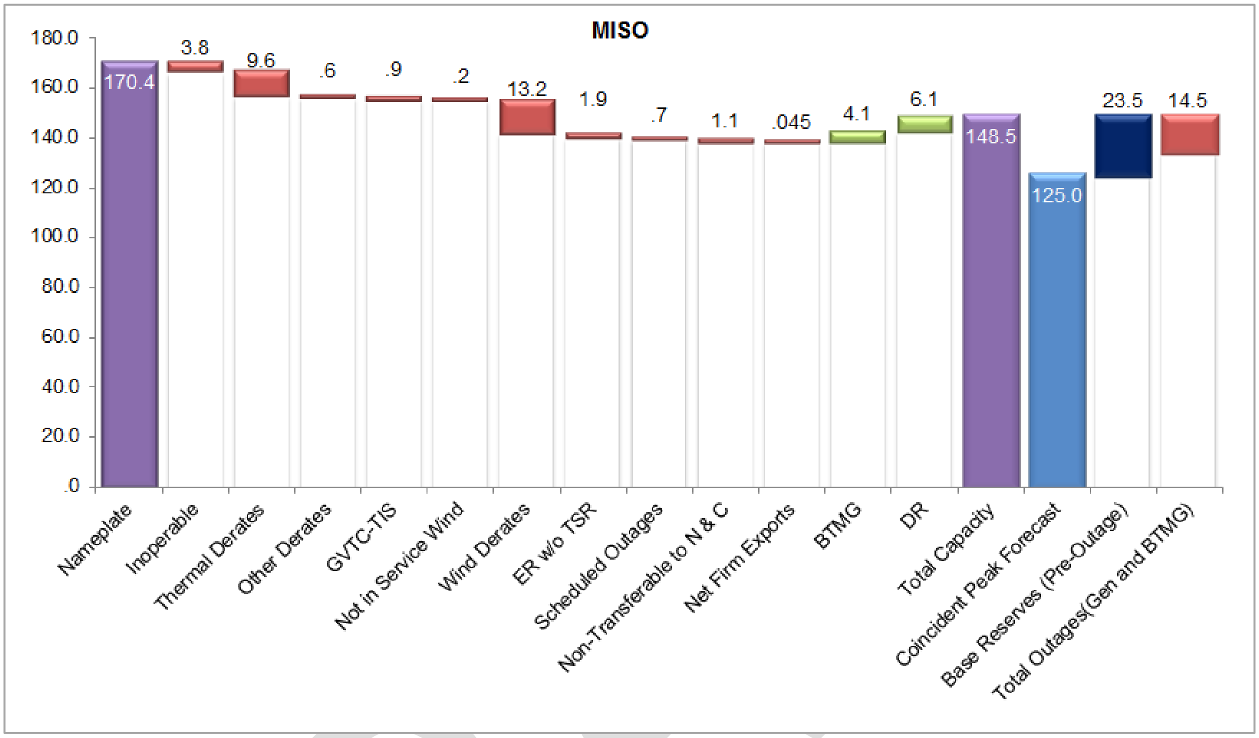


Figure 6.3-7: 2017 Summer Rated Capacity projected Base scenario (GW) showing the reduction from Installed Nameplate Resource Capacity. This includes derates and transmission limited resources.

The Probable scenario uses additional assumptions (Figure 6.3-8). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 1,500 MW contract path limitation. Additionally, any units designated as Under Study through the Attachment Y process are considered available.

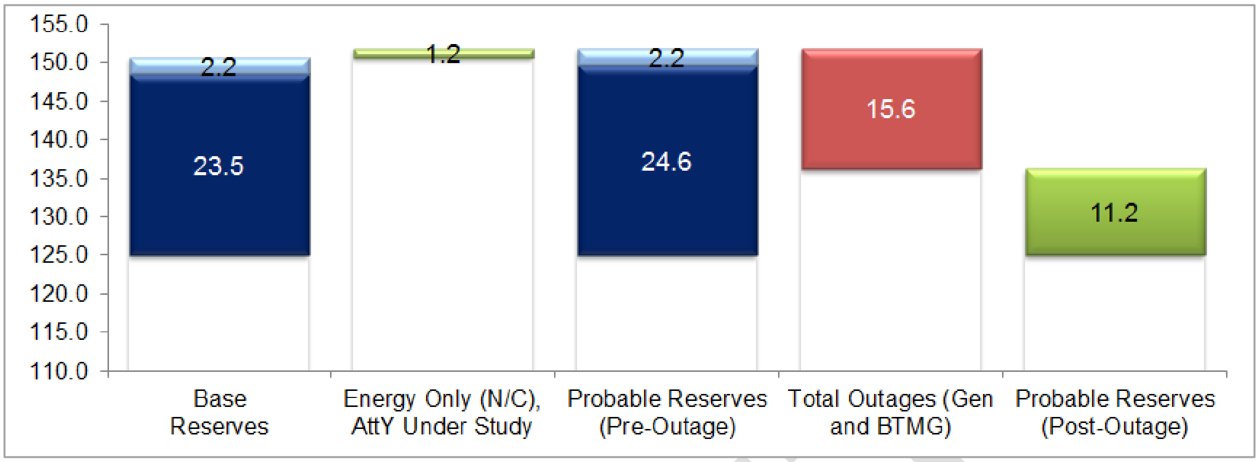


Figure 6.3-8: 2017 Summer Rated Capacity projected Probable scenario (GW), showing added capacity assumptions

The High Demand, High Outage scenario has added assumptions (Figure 6.3-9). Beginning with the Probable Reserves from the Probable Scenario (Figure 6.3-8), the load is increased to show the higher load from a 90/10 forecast. Also a higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available.

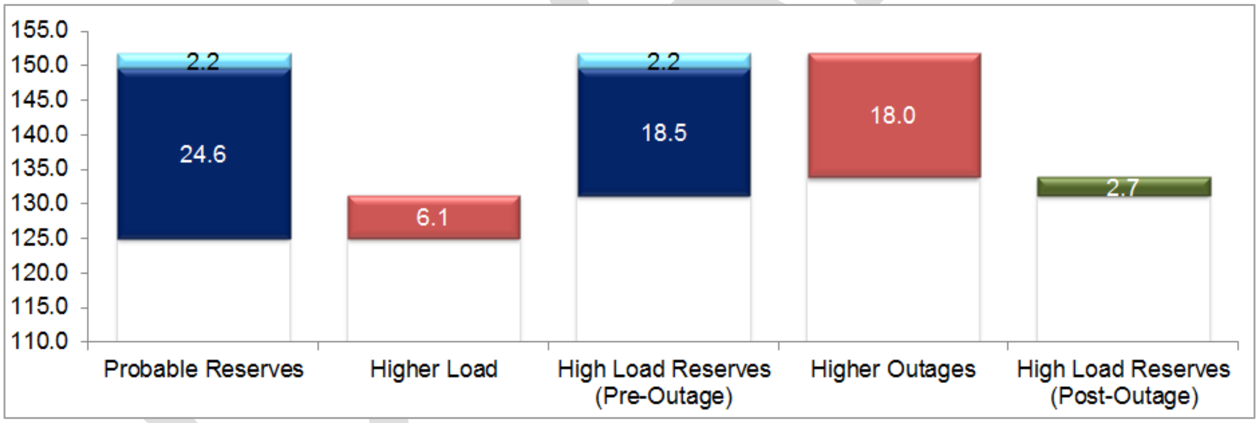


Figure 6.3-9: Summer Rated Capacity projected High Demand, High Outage scenario (GW)

2017 Summer Risk Assessment

MISO performs a probabilistic assessment on the region to determine the percent chance of utilizing Load Modifying Resources and Operating Reserves or having to curtail firm load. A risk profile is generated from this analysis (Figure 6.3-10).

It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, low water levels and other factors to lead to the curtailment of firm load. The Loss of Load Expectation (LOLE) model that MISO utilizes for PRMR takes into account the uncertainties associated with load forecasts (e.g., 50/50 versus 90/10) and generation outages (both forced and scheduled).

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.3-10). As shown, the probabilistic analysis indicated a 79.3 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 12.0 percent chance of initiating further steps to access Operating Reserves; and a 5.0 percent chance of curtailing firm load during the 2017 summer peak hour.

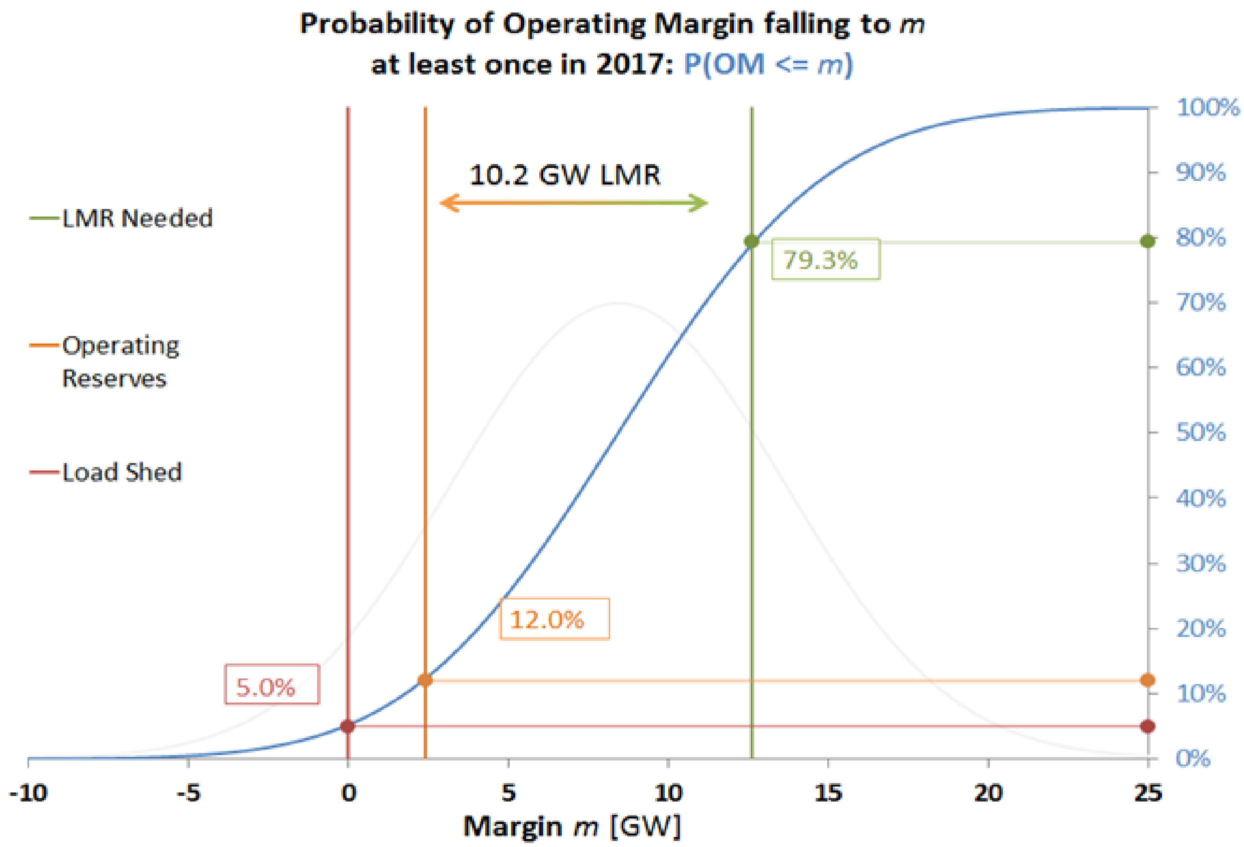


Figure 6.3-10: MISO 2016 summer chance of initiating Maximum Generation Emergency Step 2b or higher at forecasted Probable Reserve Margin

The reserves available in the Probable scenario are shown after forced, planned and maintenance outages are applied, showing the amount of Generation, BTMG, DR and Operating Reserves expected (Figure 6.3-11). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2017 summer season was 2,400 MW, which is called on as a last resort before load shed. Operating reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

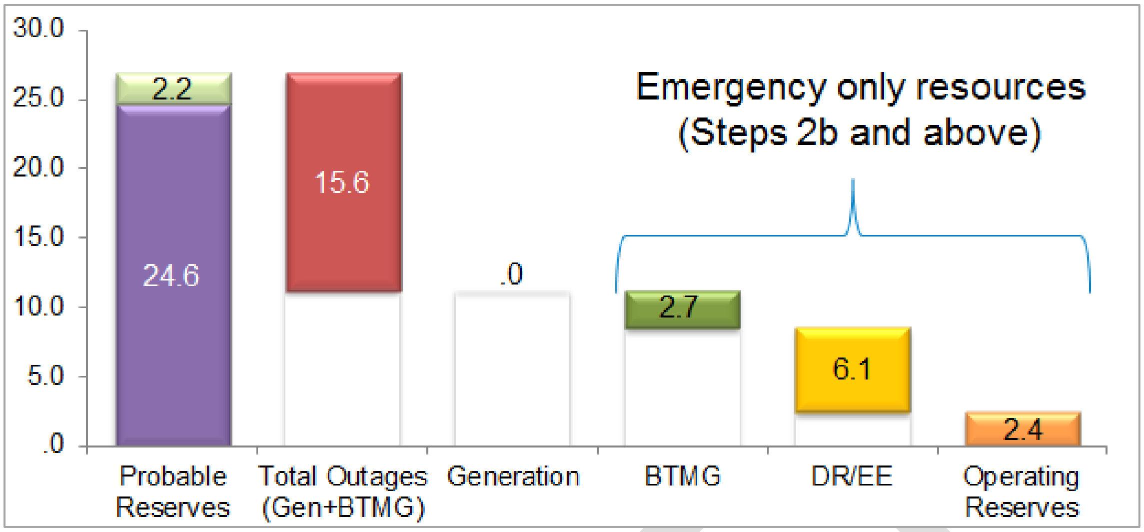


Figure 6.3-11: Summer Rated Capacity projected Probable Reserves (GW)

MISO Summer Rated Capacity Methodology

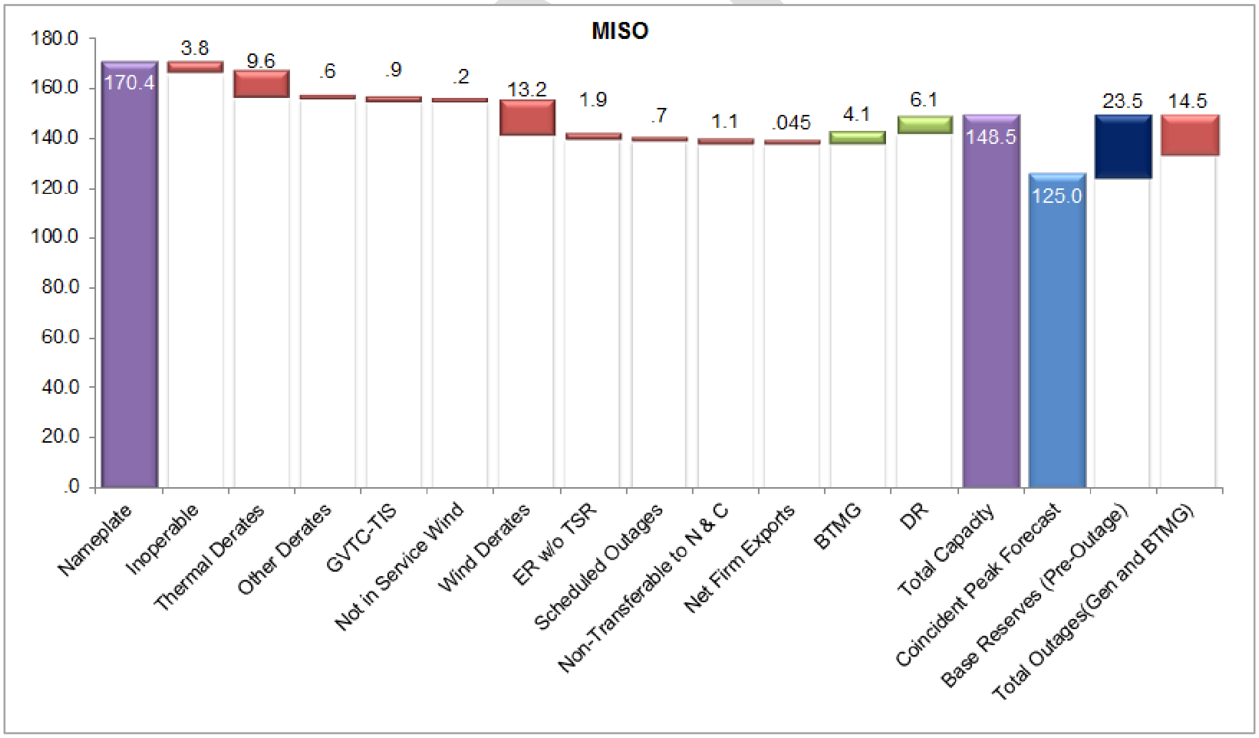


Figure 6.3-12: MISO 2017 Summer Rated Capacity waterfall chart, Base scenario (GW)

The calculation of MISO Summer Rated Capacity resources separates into 13 parts (Figure 6.3-12). Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2016-2017 Winter Resource Assessment. The 13 parts include:

1. *Nameplate*: the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable:* the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal Derates:* the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *Other Derates*: the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources (GVTC-TIS)*: the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind are the summation of differences in nameplate capacity and TIS.
6. *Not-in-Service and provisional wind*: units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind Derates*: the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *ER without TSR Energy-only:* resources with Energy Resource Interconnection Service (ERIS) without a firm point-to-point Transmission Service Right.
9. *Scheduled Outages*: Scheduled generator outages from June 1, 2017, through August 31, 2017, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler in March 2017. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."

   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.

   This calculation amounts to an expected scheduled maintenance of 696 MW.
10. *Net Firm Exports:* MISO anticipated the net firm interchange to be exporting 45 MW for the 2017 summer.
11. *Non-Transferable to MISO North and Central*: 1,134 MW of MISO South resources were excluded from the available capacity to align with 1,500 MW intra-RTO contract path.
12. *Behind-the-Meter Generation (BTMG)*: the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2017-2018 Planning Resource Auction, 4,059 MW of BTMG cleared to be available for the 2017 summer season.
13. *Demand Resource*: MISO currently separates contractual demand resource into two separate categories: Direct Control Load Management (DCLM) and Interruptible Load (IL).

    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.

    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 6,112 MW for the 2017 summer season.

6.4 Demand Response, Energy Efficiency and Distributed Generation

Although the same Applied Energy Group (AEG) forecast is used in MTEP16 and MTEP17, this section has been modified from the MTEP16 report to reflect changes for MTEP17 futures. The futures developed for MTEP17 are Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT). Each future uses a different AEG scenario provided in the forecast.

AEG developed a 20-year forecast of existing, planned and technical potential demand response (DR), energy efficiency (EE) and distributed generation (DG) programs and the associated costs in MISO and the Eastern Interconnection regions modeled in economic planning. This study, which was used in MTEP17, was completed in February 2016.

AEG received utility program data through a survey they conducted. Survey responses accounted for 93 percent of the load in 2016, and that data was supplemented with information from Energy Information Administration (EIA) Form 861.

In MTEP17, the Policy Regulations future uses the Existing Programs Plus scenario, which modeled existing 2016 program data from the utility survey and assumed a small annual increase in participation in programs through 2036 (0.5 percent increase each year; maximum 10 percent over 20 years). Peak demand and annual energy savings are broken down by Local Resource Zone (LRZ) and different cases are analyzed in the full report[45]. Summary results for the Existing Programs Plus cases are:

- Peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. Peak demand savings increase to 15 percent of the baseline summer demand by 2036.
  - On the residential side, appliance incentives, customer solar PV and customer wind turbines are the programs with the greatest estimated impact by 2026
  - On the commercial and industrial side, custom incentives, prescriptive rebates and customer wind turbines are the programs with the greatest estimated impact by 2026
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 7 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.
  - On the residential side, appliance incentives, customer wind turbines and whole-home audits are the programs with the greatest estimated impact by 2026
  - On the commercial and industrial side, custom incentives, prescriptive rebates, and retro commissioning are the programs with the greatest estimated impact by 2026
  - DG was considered a negligible percentage of these estimates with only a 0.6 percent cumulative effect by 2036

At the scoping phase of MTEP16 the Clean Power Plan (CPP) was in its draft form, which included energy efficiency as a building block. A specific scenario was created for the CPP initiative called 111(d). In the 111(d) case, to meet the compliance targets, AEG assumed utilities would see significant peak

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

demand savings starting with a slight ramp-up in 2018 to reach the EE goals in 2020[46]. Although the case specifically focuses on EE, AEG anticipated modest savings from demand response programs, as well. Savings are broken down by LRZ and different cases are analyzed in the full report. The 111(d) scenario was used for the AAT future in MTEP17, which was modeled to exceed the CPP carbon reduction target. Summary results for the 111(d) cases are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. However, peak demand savings increased to 27 percent of the baseline summer demand by 2036, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 16 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.

The MTEP17 Existing Fleet future used the Low-Demand scenario due to the low demand and energy growth rate modeled in this future. The summary results for the Low-Demand cases are:

- Peak demand savings from DR, EE and DG programs are 5 percent of the baseline summer demand in 2016. Peak demand savings increase to 13 percent of the baseline summer demand by 2036.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2016. Annual energy savings increase to 6 percent of the baseline annual energy in 2036. Throughout this forecast, energy savings come primarily from EE programs.

MTEP17 Futures	AEG Scenarios	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
		2016	2017	2018	2026	2036	2016	2017	2018	2026	2036
	Baseline Projection	118,235	119,349	120,058	126,174	136,441	678,651	685,467	690,015	732,076	801,747
PR	Existing Programs Plus Case Savings	6,326	6,900	7,466	12,481	20,263	3,221	5,326	7,447	25,314	53,225
	Existing Programs Plus Case Savings %	5%	6%	6%	10%	15%	0%	1%	1%	3%	7%
AAT	CPP 111(d) Savings	6,326	6,900	7,466	19,408	36,495	3,221	5,326	7,447	54,458	124,709
	CPP 111(d) Savings %	5%	6%	6%	15%	27%	0%	1%	1%	7%	16%
EF	Low Demand Savings	6,326	6,882	7,405	11,466	17,259	3,221	5,309	7,375	23,406	46,119
	Low Demand Savings %	5%	6%	6%	9%	13%	0%	1%	1%	3%	6%

Table 6.4-1: MTEP17 Futures Demand and Energy Savings

[46] AEG assumed additional programs will be added in order to help meet the compliance goals in the following manner: for existing programs, AEG assumed a higher participation rate as a result of presumed increase in marketing and awareness, and for programs not currently offered in the LRZ, AEG assumed that the program comes online in 2018 at a low participation rate.

The values shown in Table 6.4-1 are the same values used in MTEP16 and show technical potential of the scenarios. Specific programs modeled in the MTEP17 futures are those economically selected in the resource forecasting process.

This DR, EE and DG forecast allows MISO to analyze the impacts from these programs for transmission planning, real-time operations, and market operations (including resource adequacy). This forecast positions MISO to understand emerging technologies and the role they will play in transmission planning. Finally, the AEG forecast was incorporated into the gross Independent Load Forecast to create a net forecast. This process can be seen in Section 6.5: Independent Load Forecasting, Figure 6.5-4.

6.5 Independent Load Forecasting

The State Utility Forecasting Group (SUFG) created three 10-year horizon Independent Load Forecasts (ILF) for MISO. All three were submitted and delivered to MISO in November, the first ILF was submitted in 2014, second in 2015, and the third in 2016.

Additionally SUFG normalized historical data to create 50/50 historical data. Both Module E and ILF base are 50/50 forecasts, and this offers a more accurate comparison than with actuals. MISO wants to eliminate as much uncertainty as possible in long-term load forecasts; this is why MISO investigated ILF for any potential benefits in long-term planning. Through the three iterations and SUFG's work with MISO and stakeholders, MISO has found that ILF can consistently account for Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG) in long-term load forecasts. ILF offers a range by providing high, low and base forecasts.

The ILF is not intended to replicate or replace LSE or TO forecast processes or Module E; it is a complement long-term planning forecast to Module E. Long-term forecasts are becoming more critical due to fleet changes, renewable energy and emerging technologies such as behind-the-meter solar photovoltaic (PV), electric vehicles and energy storage. MISO will continue to use Module E for next-planning-year resource adequacy and capacity auction regardless of ILF findings.

Weather Normalized Historical

The ILF base and Module E are 50/50 forecasts. This means 50 percent of the time the load is higher than forecasted and 50 percent of the time it is lower. To offer a more direct comparison between these forecasts and actual historical data, SUFG weather-normalized actuals to create 50/50 weather normalized data for both energy and demand (Table 6.5-1 and Figure 6.5-1)[47]. This process involves electricity sales in specific areas, it involves MISO's current footprint including MISO South.

Year	2010	2011	2012	2013	2014	2015	2016
Actual	121,388	127,556	126,590	122,445	114,709	119,609	120,364
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952

Table 6.5-1: Coincident MISO peak weather normalized Historical vs. Actuals

[47] Complete weather normalized data is in the Independent Load Forecast report at https://www.misoenergy.org/Planning/Pages/IndependentLoadForecasts.aspx

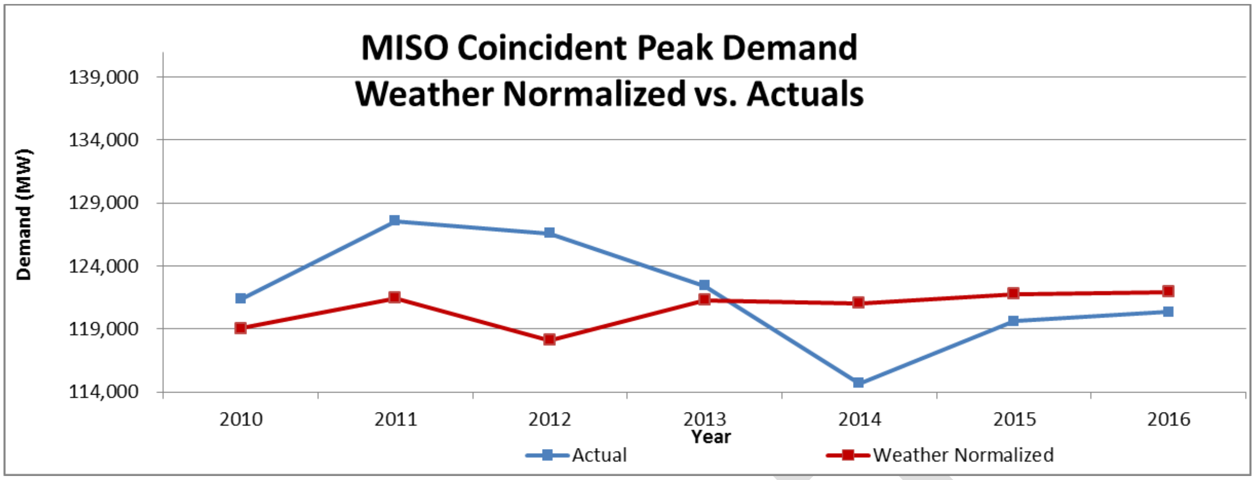


Figure 6.5-1: Coincident MISO peak weather normalized Historical vs. Actuals

Module E only provides coincident peak demand for the first year. A compound annual growth rate was found for Module E to be 0.3 percent. This growth rate was used to calculate the coincident peak demand for years 2018-2026, which contains transmission losses. This forecast is compared with the weather normalized data from SUFG because both are 50/50 values (Table 6.5-2 and Figure 6.5-2).

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952										
2017 Module E								125,002	125,377	125,754	126,131	126,509	126,889	127,269	127,651	128,034	128,418

Table 6.5-2: Coincident MISO peak weather normalized Historical vs. 2017 Module E forecast

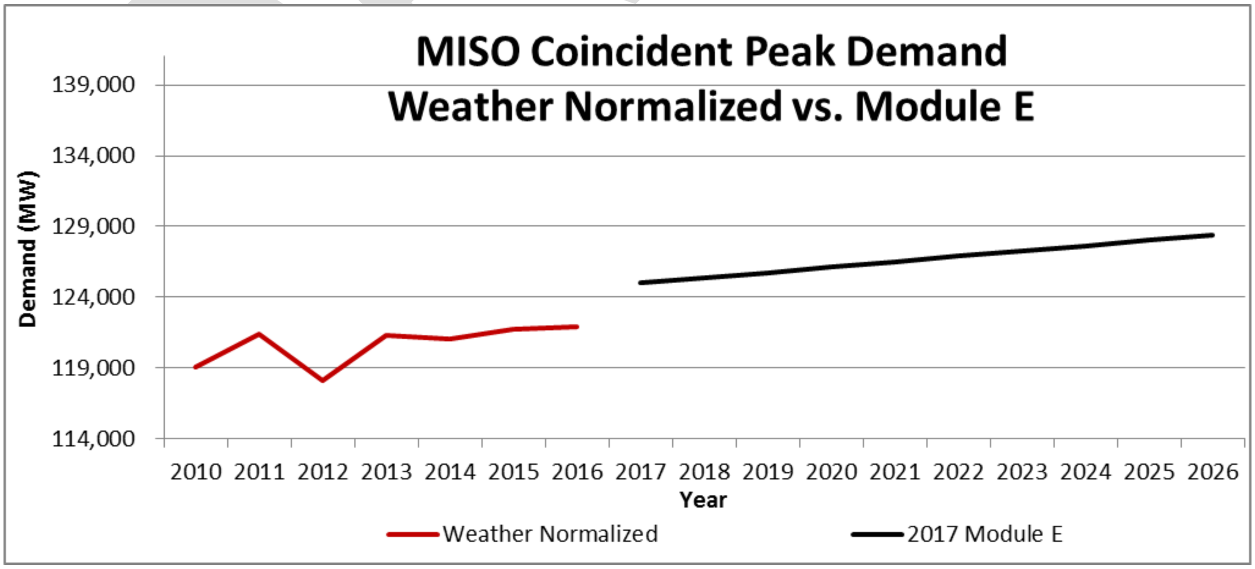


Figure 6.5-2: Coincident MISO peak weather normalized Historical vs. 2017 Module E forecast

The ILF base is also a 50/50 forecast, the gross values do not account for any EE/DR/DG whereas the net values do. The ILF forecasts were also compared to the weather normalized values (Table 6.5-3 and Figure 6.5-3).

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weather Normalized	119,043	121,443	118,103	121,291	121,069	121,787	121,952										
2016 ILF Gross								125,801	128,001	129,836	131,438	132,768	134,224	135,756	137,414	138,983	140,610
2016 ILF Net								119,554	121,449	122,972	124,252	125,243	126,376	127,580	128,902	130,130	131,407

Table 6.5-3: Coincident MISO peak weather normalized Historical vs. 2016 Base ILF forecast

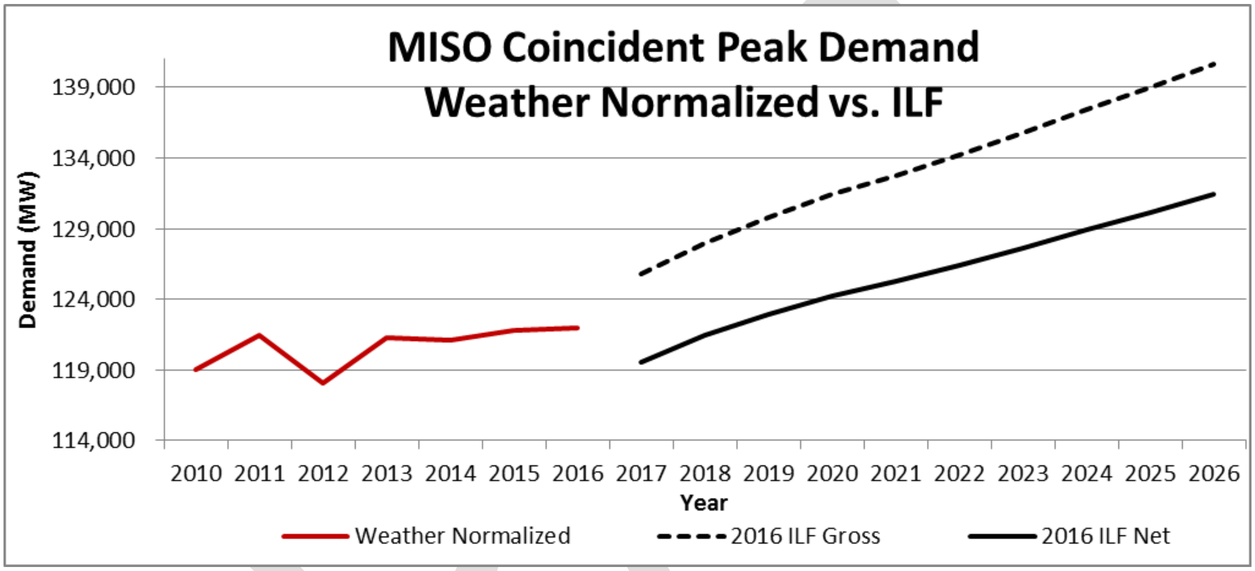


Figure 6.5-3: Coincident MISO peak weather normalized Historical vs. 2016 Base ILF forecast

Independent Load Forecast Process

MISO contracted with the SUFG from Purdue University as an independent vendor in 2014 to develop the ILF. SUFG produced econometric models for all 15 MISO states. The ILF uses public data from the Energy Information Administration to construct the forecasts. The ILF includes three main components for summer and winter seasons: annual energy for each of the 10 Local Resource Zones (LRZ) and MISO aggregate; coincident MISO peak demand (CP); and non-coincident peak demand (NCP), also known as zonal coincident peaks, for each of the 10 LRZs.

The ILF first provides un-adjusted forecasts that do not account for any EE, DR and DG existing or planned. This forecast is accompanied with the forecasts created by the Applied Energy Group (AEG) and then gets processed through EGEAS to develop net forecasts (Figure 6.5-4). A detailed description on how AEG programs are incorporated in MTEP Futures is discussed in detail in Section 5.2 MTEP Futures Development.

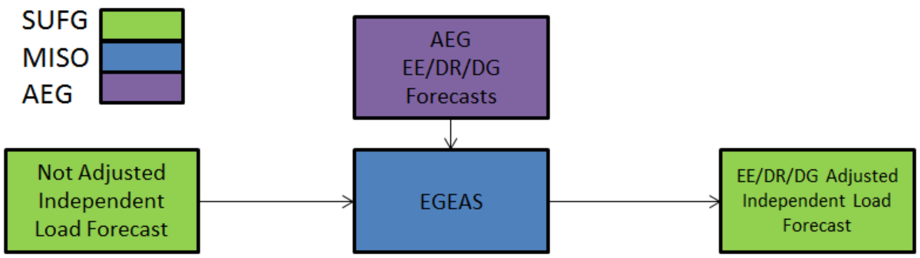


Figure 6.5-4: ILF Gross to Net Process
(gross has no EE/DR/DG adjustments; net has EE/DR/DG adjustments)

The ILF incorporates weather variables in its models and assumes normal weather conditions during the forecast period. The ILF base is a 50/50 forecast. The ILF also provides high and low forecasts, which allows for a range where the actual load might fall. The weather data used in the last two iterations was taken from a population-weighted average of multiple weather stations that represent the geographic areas in the specific state (Figure 6.5-5).

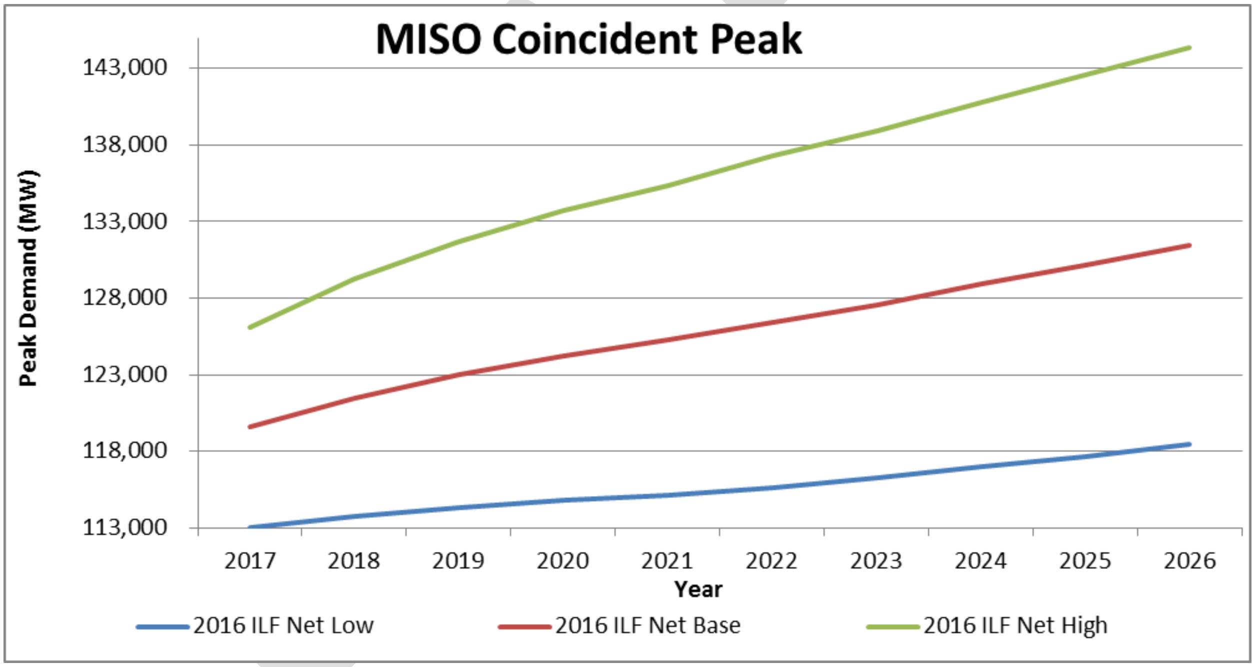


Figure 6.5-5: 2016 ILF Net Base vs. High vs. Low

What MISO Has Learned From the ILF

Through the three iterations of ILF, MISO has gained further insight and transparency into long-term load forecasts. Based on stakeholder feedback SUFG has refined its process and methodology. For example, in the 2014 ILF, SUFG created both gross and net predictions using states mandates and goals. In the 2015 and 2016 ILF, SUFG created a gross forecast and used AEG and EGEAS to create the net forecast. The difference in the Compound Annual Growth Rate (CAGR) between gross and net growth rates are significantly higher in year 1 (red) than in year 2 (blue) and year 3 (green) (Table 6.5-6).

	Year 1 (2015-2024)	Year 2 (2016-2025)	Year 3 (2017-2026)
Gross Energy	1.42	1.33	1.25
Net Energy	0.87	1.13	1.15
Gross Summer Peak	1.42	1.30	1.24
Net Summer Peak	0.86	0.96	1.06
Gross Winter Peak	1.41	1.32	1.25
Net Winter Peak	0.86	0.91	1.02

Table 6.5-6: ILF Compound Annual Growth Rates

AEG and EGEAS methodology align with MISO's current process and assumptions within MTEP. With the completion of the three ILF iterations, MISO believes it can gain valuable information from ILF and will continue to investigate how ILF may be able to assist MISO's long-term forecast (Figure 6.5-7). Long-term load forecasts are becoming more critical due to fleet changes, renewable energy, and emerging technologies like behind the meter solar PV, electric vehicles and energy storage. Proposed ILF inclusion in MTEP economic planning will be discussed with stakeholders in the Planning Advisory Committee meetings.

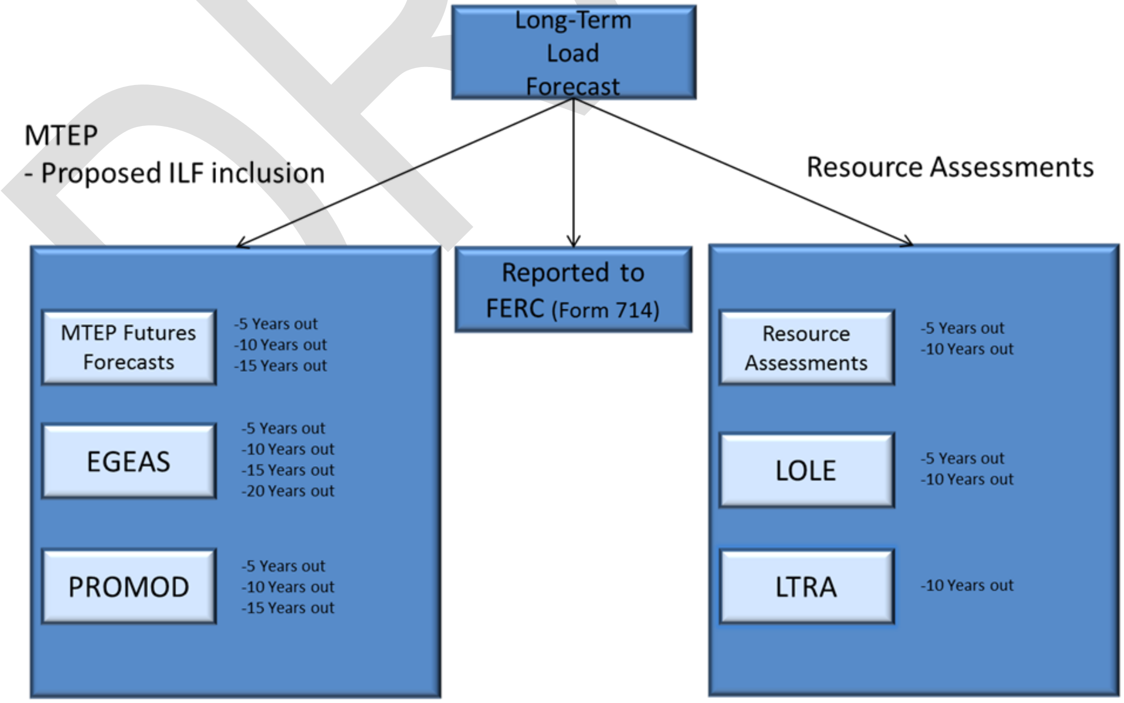


Figure 6.5-7: MISO's use of Long-term Forecasts

Book 3 / Policy Landscape

Section 7: Regional Studies

7.0 Policy Landscape Overview

MISO's generation fleet continues to evolve toward a decreased reliance on coal generation and an increased reliance on natural gas and renewable generation, despite current regulatory policy uncertainty. Both economic factors and generation fleet characteristics have important impacts on these trends.

Coal plant retirements continue to be announced in the MISO region as MISO's coal fleet ages. Based on industry and MISO fleet data, coal units generally retire by 65 years of age. MISO estimates that age-related coal unit retirements in the MISO fleet could result in the retirement of about 15 percent of the MISO coal fleet over the next 15 years. There have been no major reversals in announced retirements, despite decreased likelihood in near-term federal carbon regulations. Coal prices and production in the United States currently remain low. In addition, several nuclear units within the MISO footprint have publically announced potential retirement. However, recent discussions at the federal level about assessing the importance of preserving coal and nuclear generation for baseload fuel diversity as well as state policies could potentially extend the life of existing plants.

As coal generation retires and natural gas prices remain low, natural gas generation has comprised a growing share of MISO's thermal generation. As MISO's reliance on natural gas increases, MISO is focusing on gas-electric coordination to increase MISO's understanding of energy industry trends and the relationships between gas market drivers and electric system dispatch.

Industry analysis predicts continued reductions in capital costs for renewable resources. Relative to wind, a more significant decline in solar costs is predicted over the next 15 years as solar technology continues to mature. MISO is also studying trends of increasing distributed solar resources for future system impacts. Although the future of the current Production Tax Credit and Investment Tax Credit is unsure, the underlying costs are still declining. MISO continues to see wind and solar resource additions in the MISO region. The system currently has about 16 GW of wind generation with 31 GW in the interconnection queue and about 200 MW of solar generation with 8 GW in the interconnection queue[48].

In addition to distributed solar generation, MISO is studying emerging technologies, such as energy storage, and their system impacts. With predictions of declining costs for energy storage resources, this will likely continue to be a key industry trend with the potential for future policy implications. Potential growth in energy efficiency and demand response programs will also have an impact on MISO's future energy mix. Based on analysis from Applied Energy Group, from 10 to 26 GW of technical potential for energy efficiency and 8 to 12 GW of technical potential for demand response could be feasible in the MISO region over the next 15 years.

The possibility of federal carbon regulation has decreased notably since the 2017 Executive Order dismantling the Clean Power Plan. However, the possibility of future carbon regulation remains and should be considered in prudent long-term planning. Overall, power plant carbon dioxide emissions decreased about 15 percent from 2005-2015 across the MISO region due to industry trends and economics. MISO also continues to track and study state policies including renewable portfolio standards and energy efficiency mandates and goals. MISO will continue to follow federal and state policy as well as monitor fuel prices, plant retirements and announced member plans for any changing industry trends.

[48] Interconnection Queue data as of June 2017

7.1 MISO PJM Joint Modeling Analysis

In a precedent-setting move, MISO coordinated with PJM to perform interregional analysis on the effects of environmental regulations and policy on grid operations.

Building off of studies previously performed individually on their respective footprints, MISO and PJM coordinated on an interregional assessment of the impact of environmental regulations and policy on grid operations. The assessment utilized the most relevant information and features from the individual studies along with a common set of assumptions and a common modeling tool. The RTOs considered economic interchange, congestion on the transmission system, utilization of generation resource types, generation production costs and energy market costs. They also examined the effects of external drivers such as the price of natural gas, the effects of varying the size of the emissions trading region and the effects of using energy efficiency as a compliance mechanism.

From this joint analysis, MISO and PJM made the following key observations:

- External economic drivers may overshadow state policy choices. Natural gas prices heavily influence the cost and impact of state policy objectives by influencing resource economics (zero-emitting project viability).
- Standardization of state policy decisions may reduce associated program costs. Standardization of energy efficiency measurement and verification facilitates commoditization of credits across broader markets; and would enhance energy efficiency's value to consumers by offsetting deployment costs.
- Non-similar state policies can drive significant economic distortions along the MISO-PJM seam and exacerbate transmission cost impacts. Conversely, the ability to transact fungible products among states results in greater market efficiency.

Observations from the analysis are intended to help states in the MISO and PJM regions better understand how interregional coordination can help states achieve policy objectives with the least-adverse impacts to power system operation and at the lowest cost. The economic fundamentals rooted in the operation of organized wholesale electric markets can easily be extended to evaluation of emissions policy. States, utilities and other entities can consider the observations made from this analysis within the specific context of the Clean Power Plan or in a broader context as they consider other policy goals that can influence already dynamic economic interactions in modern wholesale electric markets.

Purpose and Background of the MISO PJM Joint Modeling Analysis[49]

The energy landscape in the MISO footprint has changed in recent years due to a combination of economic, regulatory and policy drivers. These drivers affect generation mix, reserve margins, grid reliability, dispatch and operations. These effects are expected to continue, fundamentally transforming the electric utility industry over the coming decades.

Some of the main regulatory drivers are developed by the U.S. Environmental Protection Agency (EPA) and include the Mercury and Air Toxics Standards (MATS), the National Ambient Air Quality Standards (NAAQS), the Clean Power Plan[50] (CPP) and the Cross-State Air Pollution Rule (CSAPR). This year, MISO continued to analyze the effects of environmental regulations and policy on grid operations by embarking upon an interregional assessment in coordination with PJM.

[49] For the MISO/PJM Joint Modeling Analysis full report
[50] For the Clean Power Plan Final Rule Study full report

When introduced, the CPP was widely recognized to have a potential transformative impact on the sources of power supply with its regulation of carbon dioxide emissions from the electric power sector. By request of their states and stakeholders, MISO and PJM analyzed the CPP independently in order to provide their state agencies with objective analysis they could consider in developing CPP compliance plans.

Since its introduction as a proposed rule, the CPP has garnered a significant amount of opposition, and the current political environment makes it unlikely that it will survive in its current form. The CPP, however, is only one of many policy and market drivers that states are faced with as they think about current and future electric supply.

As a follow-up to their initial studies, MISO and PJM both saw a benefit to conducting an additional joint policy evaluation using the CPP as a case study. The MISO and PJM footprints are adjacent and share a significant electrical seam. The various ways in which states could have developed compliance plans with the CPP could add additional complexity to operating generation and transmission; thus, the CPP provides a good stress test to illustrate not only the value of interregional coordination but state coordination as new policies and/or regulations are considered.

The observations of the joint modeling analysis are not recommendations for complying with the CPP and will not be used to identify transmission upgrades for inclusion into either RTO's future transmission expansion plan. However, states, utilities and other entities can consider the observations made from this analysis within the specific context of the CPP or in a broader context as they consider other policy goals that can influence already dynamic economic interactions in electric markets.

7.2 MVP Triennial Review

2017 MVP Triennial Review Report Summary

The MTEP17 Triennial Multi-Value Project (MVP) Review provides an update of the projected economic, public policy and qualitative benefits of the MVP Portfolio. The MTEP17 MVP Triennial Review's business case is on par with, if not better than, MTEP11, providing evidence that the MVP criteria and methodology works as expected. Analysis shows that projected MISO North and Central Region benefits provided by the MVP Portfolio have increased since MTEP11, the analysis from which the portfolio's business case was approved.

Analysis shows that projected benefits provided by the MVP Portfolio have increased since MTEP11.

The MTEP17 results demonstrate the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.2 to 3.4; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates $12.1 to $52.6 billion in net benefits over the next 20 to 40 years
- Enables 52.8 million MWh of wind energy to meet renewable energy mandates and goals through year 2031

Benefit increases are primarily congestion and fuel savings, largely driven by the changing MISO fleet, carbon costs and updated system landscape.

The fundamental goal of the MISO's planning process is to develop a comprehensive expansion plan that meets the reliability, policy and economic needs of the system. Implementation of a value-based planning process creates a consolidated transmission plan that delivers regional value while meeting near-term system needs. Regional transmission solutions, or MVPs, meet one or more of three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value

MISO conducted its second triennial MVP Portfolio review, per tariff requirement, for MTEP17. The MVP Review has no impact on the existing MVP Portfolio cost allocation and is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The Triennial MVP Review has no impact on the existing MVP Portfolio cost allocation. The intent of the MVP Review is to identify potential modifications to the MVP methodology for projects to be approved at a future date.

The MVP Review uses stakeholder-vetted models and makes every effort to follow procedures and assumptions consistent with the MTEP11 analysis. Metrics that required any changes to the benefit valuation due to changing tariffs, procedures or conditions are highlighted. Consistent with MTEP11, the MTEP17 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still in planning stages. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central Regions, only MISO North and Central Region benefits are included in the MTEP17 MVP Triennial Review.

Public Policy Benefits

The MTEP17 MVP Review reconfirms the MVP Portfolio's ability to deliver wind generation, in a cost-effective manner, in support of MISO States' renewable energy mandates. Renewable Portfolio Standards assumptions[51] have only had minor changes since the MTEP11 analysis.

Updated analyses find that 11.3 GW of dispatched wind would be curtailed in lieu of the MVP Portfolio, which extrapolates to 60.5 percent of the 2031 full Renewable Portfolio Standard (RPS) energy. MTEP14 and MTEP11 analyses both showed a similar percentage of their full RPS energy would be curtailed without the installation of the MVP Portfolio. The minor differences between studies can be attributed to new transmission upgrades represented in the system models and the changes in actual physical locations of installed wind turbines.

In addition to allowing energy to not be curtailed, analyses determined that 5.1 GW of wind generation in excess of the 2031 requirements is enabled by the MVP Portfolio. For their respective models years, MTEP11 and MTEP14 analyses determined that 2.2 GW and 3.4 GW of additional generation could be sourced from the incremental energy zones.

When the results from the curtailment analyses and the wind-enabled analyses are combined, MTEP17 results show the MVP Portfolio enables a total of 52.8 million MWh of renewable energy to meet the renewable energy mandates through 2031. System wide, the MTEP17 wind enablement amount is substantively similar to 2014 and 2011 analyses — 43 million MWh and 41 million MWh, respectively.

Economic Benefits

MTEP17 analysis shows the Multi-Value Portfolio creates $22.1 to $74.8 billion in total benefits to MISO North and Central Region members (Figure 7.2-1). Total portfolio costs have increased from $5.56 billion in MTEP11 to $6.65 billion in MTEP17. Even with the increased portfolio cost estimates, the increased MTEP17 congestion and fuel savings benefit forecasts result in portfolio benefit-to-cost ratios that have increased since MTEP11.

[51] Assumptions include Renewable Portfolio Standard levels and fulfillment methods

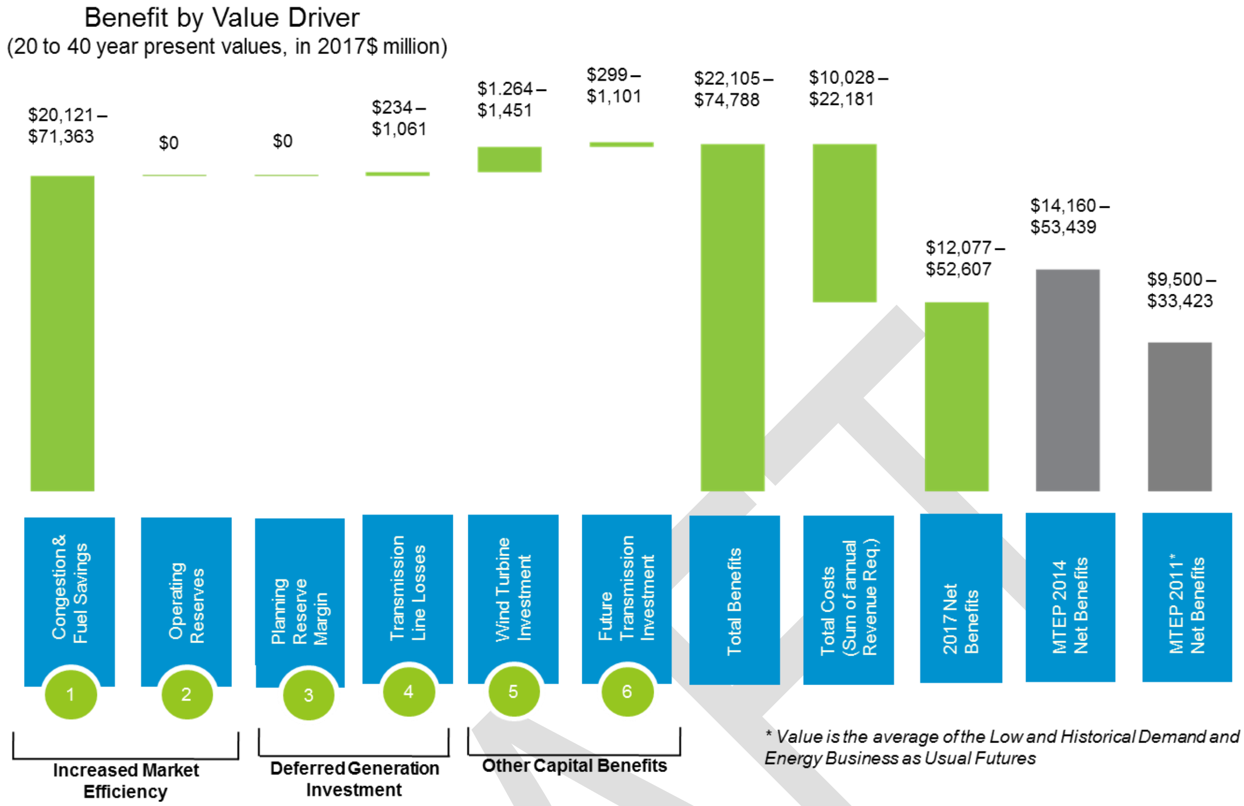


Figure 7.2-1: MVP Portfolio Economic Benefits from MTEP17 MVP Triennial Review

Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $20 to $71 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions.

The MVP Review estimates that the MVP Portfolio will yield $20 to $71 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions.

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection highly correlated to the natural gas price assumption. A sensitivity applying the MTEP14 Business-as-Usual gas price assumptions to the MTEP17 MVP Triennial Review model showed a 27 percent reduction in the 20-year MTEP14 Present Value congestion and fuel savings benefits. Also, approximately 38 percent of the difference between the MTEP17 and MTEP14 present value congestion and fuel savings benefit is attributable to the carbon costs, wind enablement, coal retirements and topology changes (Figure 7.2-2).

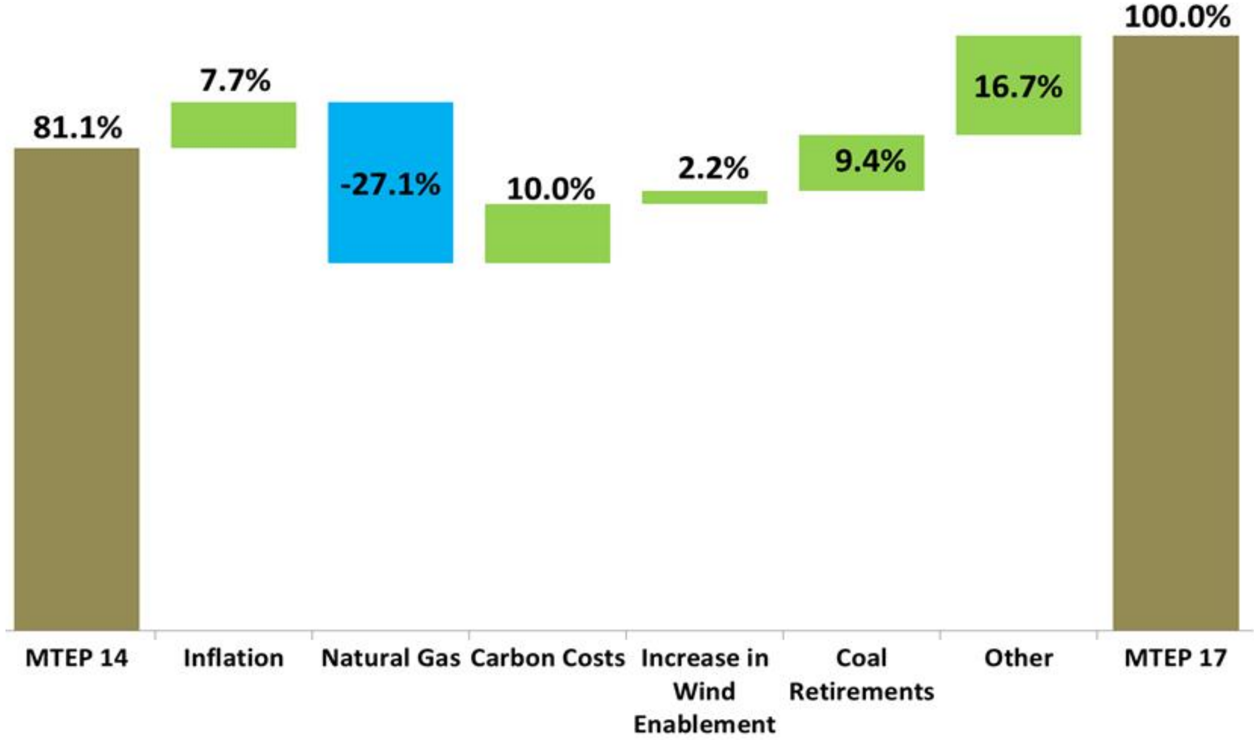


Figure 7.2-2: Breakdown of Congestion and Fuel Savings Increase from MTEP14 to MTEP17

The MTEP17 Policy Regulation future's national CO_2 emissions were priced at $5.80/ton, which increased the congestion and fuel savings benefit by 10 percent relative to MTEP14. The MTEP14 model did not include carbon emission costs in the production cost calculation. The wind enabled through the MVPs offset more expensive generation, with carbon costs, to lead to the slight increase in MVP benefits.

Within the MTEP17 Policy Regulatory (PR) future assumptions MISO forecasted approximately 16 GW of coal retirements driven by both age and policy assumptions. The MTEP14 Triennial Review models included 12.6 GW of assumed coal retirements. The coal unit retirement assumption in MTEP17 PR future resulted in an increase in congestion and fuel savings of 9.4 percent. The additional 18.9 percent in increased benefits is driven by the increase in wind enabled by the MVPs as well as topology changes from MTEP14 to MTEP17.

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduces operating reserve costs. The MVP Review does not estimate a reduced operating reserve benefit in 2017, as a conservative measure, because of the decreased number of days a reserve requirement was calculated since the MTEP11 analysis.

Deferred Generation Investment

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. Using current capital costs, the deferment from loss reduction equates to a MISO North and Central Regions' savings of $234 to $1,061 million — nearly double the MTEP11 values as a result of tighter reserve margins.

The previous MVP Triennial Review in MTEP14 estimated a deferred capacity value of $75.8 million due to the expected capacity shortage in Local Resource Zone (LRZ) 3 without the addition of the MVPs. With the refreshed analysis using updated system topology and expected capacity resources, MISO no longer expects a capacity shortfall in LRZ 3. As a result, the MVP Review does not estimate any deferred capacity benefits in the MTEP17 MVP Review.

Other Capital Benefits

The MTEP17 Triennial MVP Review found that the benefits from the optimization of wind generation siting to be $1.2 to $1.4 billion. These benefits are lower relative to MTEP11 and MTEP14 which is primarily due to a 40 percent decrease in the estimated wind capital costs.

Consistent with MTEP11, the MTEP17 MVP Triennial Review shows that the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades. The magnitude of estimated benefits is in close proximity to the estimates from MTEP11 and MTEP14; however, the actual identified upgrades are different as a result of load growth, generation dispatch, wind levels and transmission upgrades.

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each LRZ (Figure 7.2-3). The MVP Portfolio's benefits are at least 1.5 to 2.6 times the cost allocated to each zone. Differences in zonal distribution relative to MTEP11 and MTEP14 are a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), generation dispatch, wind siting and load levels.

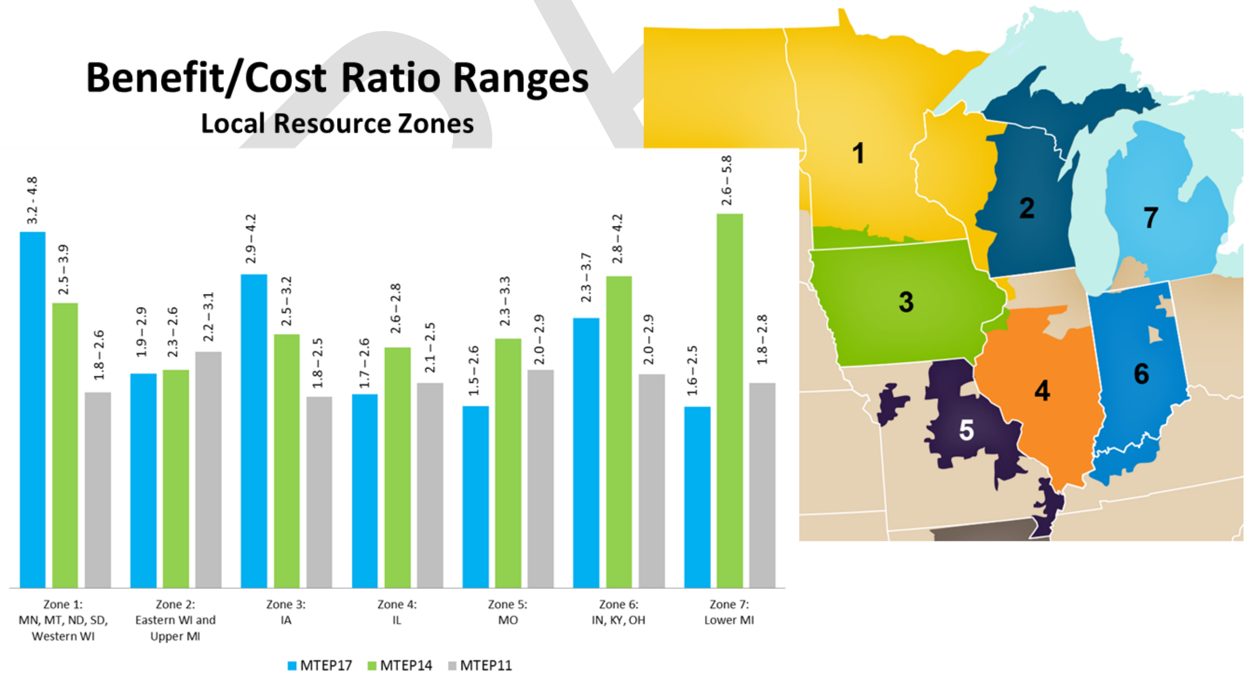


Figure 7.2-3: MVP Portfolio Total Benefit Distribution

Qualitative and Social Benefits

Aside from widespread economic and public policy benefits, the MVP Portfolio also provides benefits based on qualitative or social values. The MVP Portfolio:

- Enhances generation flexibility
- Creates a more robust regional transmission system that decreases the likelihood of future blackouts
- Increases the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time
- Supports the creation of thousands of local jobs and billions in local investment
- Reduces carbon emissions by 13 to 21 million tons annually

These benefits suggest quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the MVP Portfolio.

Historical Review

The MTEP17 MVP Review is the first cycle to provide a quantitative and qualitative look at how the in-service MVPs may have impacted certain historical market metrics. With only four of the 17 MVPs presently in service, no definitive conclusions could be made as a result of this analysis. However, correlations between congestion improvements on targeted flowgates and upward trends of wind resource interconnections and energy supplied were observed from the limited available data. As a larger statistical sample size becomes available in future reviews, a more detailed discussion on MVP impacts will be provided.

Going Forward

MTEP18 and MTEP19 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. The next full triennial review will be performed in MTEP20.

Book 3 / Policy Landscape

Section 8: Interregional Studies

8.1 PJM Interregional Study

MISO and PJM Interconnection, a Pennsylvania-based Regional Transmission Organization (RTO) are in the second year of their two-year Coordinated System Plan Study aimed at identification of Interregional Market Efficiency Projects. One project, a new 138 kV transmission line, has potential to be recommended as an Interregional Market Efficiency Project in June 2018.

Also for 2017, MISO and PJM focused their joint study efforts on codification of the Targeted Market Efficiency Project in the MISO-PJM Joint Operating Agreement and regional Tariffs; FERC Order compliance; and continuation of stakeholder interaction in the Interregional Planning Stakeholder Advisory Committee (IPSAC).

Targeted Market Efficiency Project Type

The MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC) has continued to be committed to interregional metric and process enhancements. In this effort, MISO and PJM have worked with stakeholders to identify changes to lower or remove undue hurdles to approve interregional projects.

Beginning in March 2016, MISO and PJM presented to IPSAC stakeholders a new interregional project. The new project type, Targeted Market Efficiency Project, gives more definition around the benefits and approval of projects found in the Targeted Market-to-Market Congestion or Targeted Area interregional studies. In the proposal, projects approved as Targeted Market Efficiency Projects by the Joint RTO Planning Committee (JRPC) would go directly to the RTOs' Boards for approval, obviating the need for separate regional analyses.

MISO and PJM worked extensively with stakeholders at the IPSAC and MISO's Regional Expansion Criteria and Benefits Working Group (RECBWG) to develop qualification criteria and benefits for the Targeted Market Efficiency Projects. On December 30, 2016, MISO and PJM jointly filed changes to the MISO-PJM Joint Operating Agreement (JOA) to incorporate the new project type. MISO filed accompanying regional Tariff changes, including regional cost allocation methodology, with FERC on August 4, 2017. Meanwhile, FERC held a Targeted Market Efficiency Project workshop on June 13, 2017 to better understand the RTOs' proposal. FERC ruled on October 3, 2017, conditionally accepting the JOA and Tariff changes with minimal compliance obligations. This order paves the way for MISO to recommend the five identified Targeted Market Efficiency Projects in Table 8.1-1 to the Board of Directors for inclusion in MTEP17.

Targeted Market-to-Market Congestion Study

In 2016, due to appreciable levels of market-to-market congestion, MISO and PJM decided to continue their annual focus on resolving historical congestion while helping to inform future metric and process enhancements. This near-term study evaluates historical market-to-market congestion to find small but important fixes, and was initially dubbed Quick Hits.

For the 2016 study, MISO and PJM analyzed historically congested market-to-market flowgates. Flowgates with significant congestion — day-ahead plus excess congestion fund — in 2014 and 2015 were considered initially. MISO and PJM worked to identify valuable projects on the seam. A valuable project would relieve known market-to-market issues; be completed in a relatively short time frame; have a quick payback on investment; and not be a greenfield project. MISO and PJM coordinated with facility owners to identify the limiting equipment and potential upgrades. Limited reliability and production cost analyses were used to confirm the projects' effectiveness in relieving congestion. Potential projects are recommended for MISO's MTEP17 and PJM's Regional Transmission Expansion Plan (RTEP) 2017 inclusion.

As of December 2016, MISO and PJM had narrowed down the potential upgrades (Table 8.1-1). Due to confidentiality concerns, the specific upgrade details will be shared with stakeholders after MISO/PJM board approval. The Market-to-Market flowgates are identified with planning level project costs, calculated project benefits, and RTO cost share.

Facility	Transmission Owner(s)	TMEP Cost	TMEP Benefit	Benefit Allocation (%PJM / %MISO)
Burnham – Munster 345 kV	CE, NIPS	$7,000,000	$32,000,000	88 / 12
Bayshore – Monroe 345 kV	ATSI, ITC	$1,000,000	$17,000,000	89 / 11
Michigan City – Bosserman 138 kV	NIPS, AEP	$4,600,000	$29,600,000	90 / 10
Reynolds – Magnetation 138 kV	NIPS	$150,000	$14,500,000	41 / 59
Roxana – Praxair 138 kV	NIPS	$4,500,000	$6,500,000	24 / 76

Table 8.1-1: MISO-PJM Targeted Market Efficiency Projects

FERC Order 1000

On October 28, 2016, FERC conditionally accepted, subject to further compliance, MISO and PJM's June 20, 2016 Third Compliance Filing under the Order 1000 interregional docket. MISO submitted its Fourth Compliance Filing on November 22, 2016. FERC accepted the revisions on January 9, 2017 with no additional compliance directives, thus concluding FERC Docket ER13-1943.

FERC Docket EL13-88

Following an initial September 11, 2013, "206" complaint by Northern Indiana Public Service Co. (NIPSCO) on how MISO and PJM perform interregional transmission planning, and subsequent June 15, 2015, FERC technical conference, FERC issued an Order on Complaint and Technical Conference in Docket EL13-88 (NIPSCO Order) on April 21, 2016. MISO and its filing partners complied with all directives and status updates through filings in June, August, October, and December of 2016.

FERC issued an Order on Rehearing and Compliance on January 19, 2017. It accepted the June and December MISO-PJM Joint Operating Agreement and Tariff changes, ruled on open rehearing and clarification requests, and ordered seven additional compliance directives. Notable changes that were accepted by the filing were the removal of an interregional benefit-to-cost ratio (i.e. the "third hurdle"); the use of regional benefits as the interregional cost split; and the removal of the $5 million threshold and lowering of the 345 kV threshold to 100 kV for Interregional Market Efficiency Projects with PJM. In ruling on the clarification requests, FERC confirmed that the Interregional Market Efficiency Project thresholds were only lowered on the seam with PJM and added a compliance directive for MISO to determine the cost allocation for sub-345 kV Interregional Market Efficiency Projects.

On April 24, 2017, MISO and PJM submitted compliance directives for the January 19, 2017, order. MISO and the MISO TOs requested, and were granted from FERC, an 18-month extension request on the regional cost allocation of sub-345 kV Interregional Market Efficiency Projects. This extension aligns with a broader cost allocation reform occurring at the RECBWG, expected to conclude in the second half of

2018. As detailed below, there is potential for a sub-345 kV Interregional Market Efficiency Project to be recommended from the 2 year Coordinated System Plan Study. If this occurs before MISO's compliance obligation on sub-345 kV IMEP cost allocation, MISO and its stakeholders in the RECBWG would need to file cost allocation for that project.

2 Year Coordinated System Plan Study

MISO and PJM are concluding the second year of their two-year Coordinated System Plan Study aimed at identification of Interregional Market Efficiency Projects. The first year, 2016, focused on issue identification and 2017 focuses on project solicitation and evaluation.

MISO published regional issues, for interregional project consideration, on January 16, 2017. MISO solicited interregional projects from stakeholders through the end of February 2017, running concurrent with PJM's regional project solicitation window. MISO and PJM evaluated interregional project proposals submitted to both regional processes.

The RTOs received eight interregional project proposals from six proposing entities. Three projects are upgrades and five are greenfield. The cost ranges between $1 million and $198 million (in-service year dollars). Notably, half of the projects are sub-345 kV, which now qualify as MISO Market Efficiency Projects after FERC's EL13-88 ruling. Analysis is expected to continue through the end of October 2017.

One project, a new Thayer – Morrison 138 kV transmission line, has potential to be recommended as an Interregional Market Efficiency Project in June 2018. The project addresses congestion on Goodland – Reynolds 138 kV and Paxton – Gifford 138 kV and shows benefits in excess of cost. Additional analyses, including a no-harm reliability study, are expected to be completed before the October 20, 2017 IPSAC. Due to the open sub-345 kV Interregional Market Efficiency Project cost allocation issue, the Thayer – Morrison 138 kV project will be recommended to the RTOs' respective Boards in June 2018, assuming it continues to meet Interregional Market Efficiency Project criteria and passes regional benefit-to-cost tests. MISO will confirm if the project qualifies for the Transmission Developer Qualification and Selection process.

Interregional Planning Stakeholder Advisory Committee

In additional to the previously mentioned interregional efforts, all discussed at the IPSAC, MISO and PJM performed their 2017 annual issues review focused on reliability projects. The RTOs found no opportunities for an Interregional Reliability Project and shared their conclusion at the March 24, 2017, IPSAC.

8.2 Southwest Power Pool Coordinated System Plan

The 2016 MISO-SPP Coordinated System Plan (CSP) study was performed to evaluate the combined MISO and Southwest Power Pool (SPP) transmission systems in an effort to identify mutually beneficial transmission improvements. The study was a nearly yearlong effort that began on May 31, 2016. MISO and SPP staff focused efforts on an economic analysis of a targeted set of transmission needs identified by MISO and SPP's respective regional planning processes along the MISO and SPP border.

MISO and SPP evaluated seven unique transmission needs in the 2016 CSP that were identified in each company's transmission planning process: MISO's MTEP 16 and SPP's 2017 Integrated Transmission Planning 10-year assessment (2017 ITP10). This approach of targeting transmission needs identified by the regional planning processes was chosen in response to stakeholder feedback and to make the joint study process more efficient by leveraging much of the regional study work. MISO and SPP used this approach to determine the existence of more efficient or cost-effective interregional transmission solutions beyond any regional solutions within 2017 ITP10 and MTEP16. Beginning with the list of seven targeted needs, staff and stakeholders collaborated to propose potential Interregional Projects to solve the identified transmission issues. The proposed Interregional Projects were then tested for Adjusted Production Cost (APC) benefits. Based on those results, MISO and SPP identified one transmission project for consideration as an Interregional Project:

- Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls

The 2016 CSP study demonstrated this project provides benefit to both MISO and SPP as well as APC benefits that exceed the cost of the project over the initial 20 years of the project's life. As a result the Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls project was recommended by MISO and SPP to the Interregional Planning Stakeholder Advisory Committee (IPSAC) for endorsement to move from the interregional portion of the study into the regional review process of each respective region. Both the MISO and SPP portions of the IPSAC[52] endorsed this recommendation with no opposition. Based on that recommendation, the MISO-SPP Joint Planning Committee (JPC) voted in favor of approving this project for review in both the MISO and SPP regional review processes.

In accordance with MISO's Tariff and BPM-020, MISO performed a regional review of the proposed I-18 Interregional Project recommended by the JPC to MISO and SPP. The regional review scope included robustness testing and sensitivity analysis consistent with efforts performed through the MCPS process to determine the extent of benefits to the customers of MISO's region. MISO also evaluated several alternative projects to determine if the I-18 Interregional Project was the most cost-effective and efficient solution. Additionally, MISO evaluated the impacts on costs due to potential unreserved use charges by SPP. The result of MISO's regional review process has concluded that although the I-18 project may be beneficial to MISO there were two alternatives that provided equal or more benefits at a much lower cost. The business cases for the I-18 interregional project were also diminished by the potential unreserved use charges by SPP. Therefore, MISO did not recommend the I-18 project for further consideration as there were two more cost-effective and efficient solutions

[52] The MISO portion of the IPSAC is made up of the voting sectors of the Planning Advisory Committee (PAC) and SPP's portion of the IPSAC is made up of the Seams Steering Committee (SSC) and non-SSC transmission owners interconnected with MISO.

Study Process

The Joint Operating Agreement (JOA) establishes a Joint Planning Committee (JPC) comprised of representatives of both MISO and SPP. The JPC is the decision-making body that is responsible for all aspects of coordinated interregional transmission planning, including the development of a CSP. The JPC is charged with verifying that the study is conducted in accordance with the requirements of the JOA and that the results of the study are accurate and meet the expectations of the JPC and IPSAC based on the study scope.

The IPSAC provides a forum and an opportunity for stakeholders to review the development of the CSP study and to provide guidance and recommendations to the JPC. IPSAC participation is open to all stakeholders.

On an annual basis, MISO and SPP have agreed to review potential transmission issues identified by each Regional Transmission Organization or any stakeholder at an IPSAC meeting as part of an Annual Issues Review process. The Annual Issues Review is administered by the JPC in coordination with the IPSAC to determine whether there is a need for MISO and SPP to perform a CSP study. When MISO and SPP determine a CSP study is warranted, the Order 1000 interregional coordination procedures outlined in the JOA are used to guide the study process.

The purpose of the MISO-SPP CSP study is to jointly evaluate seams transmission issues and to identify if there are transmission solutions that provide benefit to both MISO and SPP and are more efficient or cost effective than regional transmission solutions. This study incorporates an evaluation of economic seams transmission issues and an assessment of potential reliability violations.

At the completion of the CSP study, the JPC produces a draft report documenting the study, including transmission issues evaluated, studies performed, solutions considered, and if applicable, the recommended Interregional Projects with the associated interregional cost allocation. The draft report is made available for stakeholder review. Taking into consideration the recommendation of the IPSAC, the JPC shall meet and vote on whether to recommend any Interregional Project(s) and the associated interregional cost allocation identified in the CSP study report to both MISO's and SPP's respective regional review processes for review and approval by the respective Board of Directors.

The Annual Issues Review IPSAC meeting was held on March 9, 2016, at the SPP offices in Little Rock, AR. Multiple stakeholders, along with MISO and SPP staff, presented proposed transmission issues that were considered for evaluation in the CSP study. The feedback from stakeholders at this meeting indicated that there was a strong consensus for moving forward with a CSP study starting in 2016.

Following the IPSAC, the JPC held a meeting to decide if a CSP study would be performed in 2016. The 2016 CSP study was formally initiated on May 31, 2016, when the JPC voted in favor of performing a 2016 CSP Study. The JPC's decision was based upon the recommendation of the IPSAC which voted to recommend to the JPC to commence a joint study in 2016. While the JOA allows for up to 18 months to complete the study, SPP and MISO staff committed to and achieved a completion date of April 2017.

Economic Analysis

Solution Identification and Development

To start the CSP process, MISO and SPP first analyzed their regional studies to find areas of congestion along the seams that could potentially be solved by an interregional project. Once those lists were created, MISO and SPP staff collaborated with stakeholders to compare the regional needs in order to identify areas of common congestion that were most likely to benefit from the collaboration. MISO and SPP agreed to evaluate seven need areas as part of the 2016 CSP study, which were presented at the September 7, 2016, IPSAC meeting (Table 8.2-1 and Figure 8.2-1).

2016 MISO-SPP CSP Joint Needs List		
Need	**Constraint**	**Location**
1	Rugby WAUE - Rugby OTP Tie FLO Rugby – Balta 230 kV	SPP-MISO Tie
2	Hankinson - Wahpeton 230 kV FLO Jamestown - Buffalo 345 kV	MISO
3	Sub3 - Granite Falls 115 kV Ckt1 FLO Lyon Co. 345/115 kV transformer	SPP-MISO Tie
4	Sioux Falls - Lawrence 115 kV FLO Sioux Falls - Split Rock 230 kV	SPP-MISO Tie
5	Northeast - Charlotte 161 kV FLO Northeast - Grand Ave West 161 kV	SPP
6	Neosho - Riverton 161 kV FLO Neosho - Blackberry 345 kV	SPP
7	Brookline 345/161 kV Ckt 1 Transformer FLO Brookline 345/161 kV Ckt 2 Transformer	SPP

Table 8.2-1: 2016 MISO-SPP CSP joint needs list

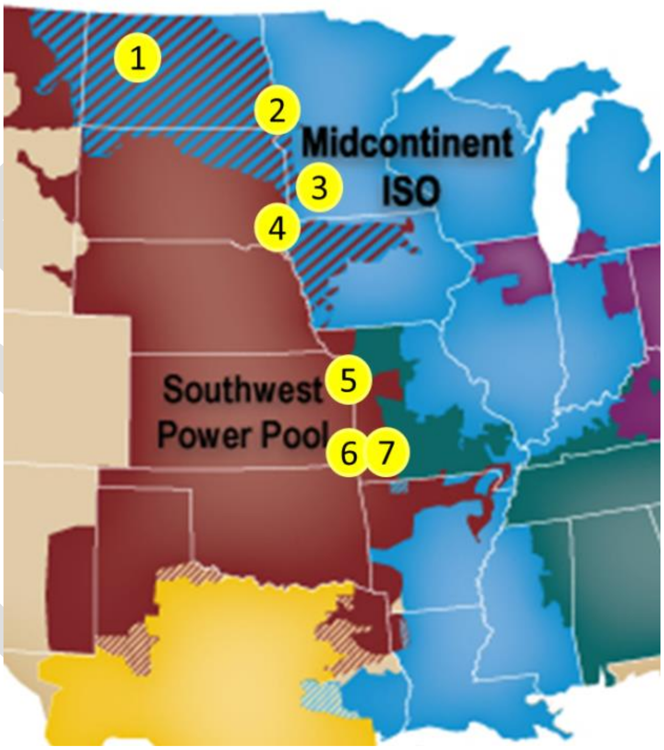


Figure 8.2-2: 2016 MISO-SPP CSP needs map

The seven needs targeted in the 2016 CSP study guided the development and evaluation of interregional transmission solution ideas. Solutions were solicited through the MISO-SPP IPSAC meetings, and each respective Regional Transmission Organization staff and stakeholders proposed transmission projects.

SPP and MISO staff also leveraged proposed solutions that had been previously submitted into their respective regional processes.

By the October 2016 deadline, stakeholders submitted a total of 36 projects (34 unique) for evaluation in the 2016 CSP study (Table 8.2-2). In addition to stakeholder submissions, MISO and SPP staff submitted 10 additional projects for consideration. No stakeholder-developed solutions were submitted for need No. 5, so MISO and SPP staff used staff-proposed solutions to evaluate that particular need.

2016 MISO-SPP CSP Project Summary		
Need	Constraint	Number of Stakeholder Solutions
1	Rugby WAUE Rugby OTP Tie FLO Rugby – Balta 230 kV	2
2	Hankinson Wahpeton 230 kV FLO Jamestown Buffalo 345 kV	11
3	Sub3 Granite Falls 115 kV Ckt1 FLO Lyon Co. 345/115 kV transformer	2
4	Sioux Falls Lawrence 115 kV FLO Sioux Falls Split Rock 230 kV	7
5	Northeast Charlotte 161 kV FLO Northeast Grand Ave West 161 kV	0
6	Neosho Riverton 161 kV FLO Neosho Blackberry 345 kV	8
7	Brookline 345/161 kV Ckt 1 Transformer FLO Brookline 345/161 kV Ckt 2 Transformer	6

Table 8.2-2: Stakeholder project submission summary

Economic Transmission Solution Evaluation

APC Methodology

MISO and SPP used an agreed-upon Adjusted Production Cost (APC) metric over a multi-year analysis to jointly evaluate the benefits to the combined MISO-SPP region and to each region individually. The APC is calculated for each simulated year (2020, 2025 and 2030) and interpolated benefits for intermediate years. Benefits for years beyond the last simulated year were based on extrapolation. The total project benefit was determined by calculating the present value of annual benefits for the first 20 years of project life after the projected in-service date.

The APC benefit metric is based upon the impact of the project on adjusted production cost, which is adjusted to account for purchases and sales. Both MISO's and SPP's APC represent the summation of the APC for the defined areas in each region. Each area's production cost was adjusted for purchases and sales two ways:

- For each simulation hour in which an area is selling interchange, the APC was calculated by multiplying the interchange sales MW by the area's generation-weighted Locational Marginal Price (LMP) and then subtracting this value from the area's production cost
- For each simulation hour in which an area is purchasing interchange, the APC was calculated by multiplying the interchange purchase MW by the area's load-weighted LMP and then adding this value to the area's production cost

While the JOA outlines how APC should be calculated for evaluating benefits for purposes of determining interregional cost allocation of potential Interregional Projects, MISO calculates APC differently in its regional planning processes than the method used by SPP and stated in the JOA. Instead of using load-weighted LMP to price purchases and generation-weighted LMP to price sales, generation-weighted LMP is adopted for pricing both purchases and sales in current MISO regional APC metrics. The difference in pricing mechanisms can lead to varying results between the benefits calculated in the CSP and the benefits determined by MISO's regional review process.

Screening Process

A preliminary screening analysis was performed on all proposed transmission solution ideas to determine the solution ideas that have the most potential and warrant further evaluation. All transmission solution ideas with potential value were evaluated for APC benefits to MISO and SPP (Table 8.2-3). If there were projects that appeared to be electrically equivalent, only one of the projects was evaluated.

For the preliminary screening analysis, the benefit-to-cost ratio (B/C) for each proposed project was calculated by using APC benefit results of the 2025 model year compared to the 2025 model year estimated costs. If the one-year B/C was at least 0.5, the project was considered to have passed the preliminary screening analysis. A complete list of screening results can be found in Appendix A.

Solution ID	Solution Description	Addressed Need ID #	SPP & MISO B/C
I-1	Rugby 115 kV Breaker/Line Addition	1	5.23
I-1_2	Closes NO switch at North Harvey 115	1	64.62
I-2	Rolette 230 kV station	1	0.86
I-4	Jamestown 345 kV (OTP) to Jamestown 230 kV (WAPA) 230 kV Tie	2	0.92
I-5	Replace Hankinson and Wahpeton wavetraps	2	20.08
I-6	Spiritwood 115 kV to Jamestown 115 kV line	2	1.00
I-9	Construct new Rose substation at the juncture of the Jamestown - Buffalo 345 kV and Jamestown (WAPA) - Pickert 230 kV line	2	0.63
I-11	Hankinson - Wahpeton 230 kV Rebuild	2	1.66
I-12	Hankinson - Maple River 230 kV	2	1.26
I-14	2nd Lyon County 345/115 kV Transformer	3	1.57
I-17	Lawrence - Sioux Falls 115 kV Terminal Equipment Upgrades	4	6.68
I-18	Loop One Split Rock - Lawrence 115 kV Ckt into Sioux Falls	4	1.89
I-18c	Loop Sioux Falls - W. Brandon 115 kV into Split Rock	4	0.82
I-18d	Loop Sioux Falls - Beresford 115 kV into Lawrence	4	1.01
I-18e	De-energize Lawrence - Sioux Falls 115 kV	4	45.78
Staff Sol 1	Northeast - Charlotte 2 ohm series reactor	5	27.97
Staff Sol 2	Crosstown - Blue Valley 161 kV line	5	2.59
I-19	Tap Neosho - Delaware 345 kV line plus Riverton - tap 345 kV line add new 345/161 kV transformer at Riverton	6	0.86
I-20	Lacygne - Morgan 345 kV line	6	0.63
I-24	Lacygne - Blackberry 345 kV line plus 345/161 kV transformer and Blackberry - Asbury 161 kV line	6	0.85
I-28	James River - Brookline 345 kV line plus 345/161 kV transformer	7	0.69
Staff Sol 3	Morgan 345/161 kV Transformer plus Morgan - Brookline 161 kV uprate	7	2.41

Table 8.2-3: Projects that passed screening

Benefit-to-Cost Analysis

MISO used a 20-year net present value calculation of benefits and costs to calculate an indicative B/C ratio for the proposed transmission solutions that passed the preliminary screening analysis[53]. Benefits were calculated by the change in APC with and without the proposed Interregional Project that passed the screening process. The APC was adjusted to account for purchases and sales. The APC benefit metric was calculated for the simulated years 2020, 2025 and 2030. Benefits for intermediary years were calculated using interpolation and years beyond 2030 used extrapolation. The period covered by the

[53] There is not a B/C ratio requirement in the CSP study.

benefit and cost calculation was 20 years starting with the project's in-service year[54]. The annual costs were estimated using each RTO's own respective ATRR/ARRs[55] based on whether the project was located in MISO or SPP. The present value calculation assumed an 8 percent discount rate.

For the 2016 CSP study, four projects passed the Interregional Project criteria defined in the JOA.

- Loop One Split Rock - Lawrence 115kV Ckt into Sioux Falls
- Crosstown - Blue Valley 161 kV line
- Lacygne - Blackberry 345 kV line plus 345/161 kV transformer and Blackberry - Asbury 161 kV line
- James River - Brookline 345 kV line plus 345/161 kV transformer

Loop One Split Rock - Lawrence 115 kV Ckt into Sioux Falls

The proposed Interregional Project, Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls, is a proposed new transmission project located near Sioux Falls, S.D. (Figure 8.2-2). This project has an estimated in-service date of 2021.

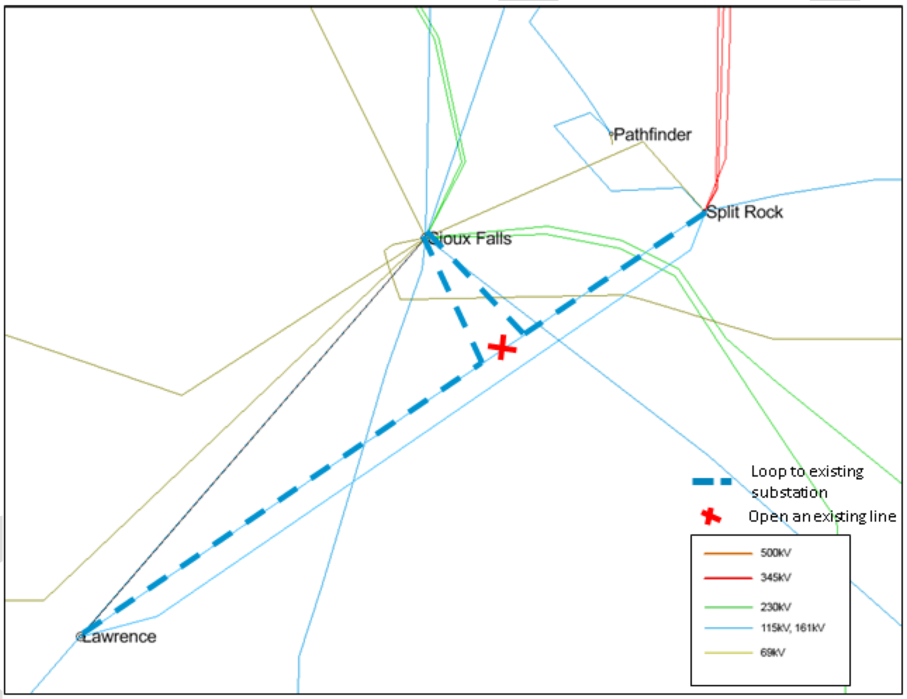


Figure 8.2-2: Loop One Split Rock - Lawrence 115 kV Ckt into Sioux Falls

This project was proposed to relieve congestion on the Lawrence to Sioux Falls 115 kV flowgate. MISO and SPP's analyses show the project completely relieves the congestion on this flowgate and provides benefit to both parties.

MISO estimated a scoping level cost estimate of approximately $6.15 million for this project, which has been reviewed by SPP[56]. Assuming the in-service date of 2021, the $6.15 million cost results in a 20-year

[54] Initially MISO and SPP have made the assumption that the in-service date for all projects is 2021.
[55] ATRR/ARR: Annual Transmission Revenue Requirement/Annual Revenue Requirement
[56] 2016 dollars

present value cost of $7.51 million[57]. MISO and SPP's 20-year present value benefit analysis shows that MISO and SPP are estimated to collectively receive $27.83 million[58] in APC benefit over the first 20 years of the project's life, resulting in a B/C ratio of 3.71. Of the $27.83 million of APC benefit, SPP is estimated to receive $5.15 million with MISO receiving $22.68 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, both MISO and SPP's B/C ratio is 3.71. Based on these numbers, both MISO and SPP supported the recommendation of this project into the regional review process.

Crosstown - Blue Valley 161 kV line

The proposed Interregional Project, Crosstown – Blue Valley 161 kV, is a proposed new transmission project near Kansas City, Mo. (Figure 8.2-3). This project has an estimated in-service date of 2021.

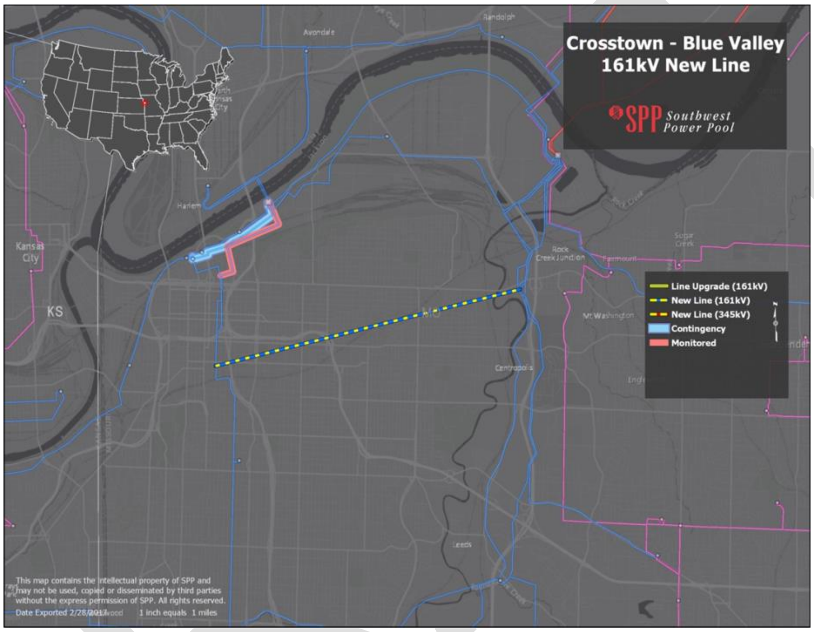


Figure 8.2-3: Crosstown - Blue Valley 161 kV line

This project was proposed to relieve congestion on the Northeast to Charlotte 161 kV flowgate. MISO and SPP's analyses show that relieving the congestion on this flowgate provides benefit to both parties. This proposed project is expected to relieve all of the congestion on the Northeast to Charlotte 161 kV flowgate.

SPP estimated an engineering and construction (E&C) cost estimate of approximately $8.06 million[59] with an assumed in-service date of 2021. The $8.06 million E&C cost results in a 20-year present value of $9.84 million[60]. MISO and SPP's 20-year benefit analysis shows that over the first 20 years of the project's life, MISO and SPP are estimated to receive $35.21 million in APC benefit resulting in a 20-year B/C ratio of 3.58. Of the $35.21 million of APC benefit, SPP is estimated to receive approximately $23

[57] The 20-year present value cost and benefit numbers here are calculated using SPP's 18.16 percent NPCC, factoring in depreciation, and discounting at 8 percent. The numbers calculated used MISO's Gross-Plant Weighted annual charge rate and 8 percent discount rate are similar to SPP's.

[59] 2016 dollars

[60] The 20-year present value cost and benefit numbers are calculated using SPP's 18.16 percent NPCC, factoring in depreciation, and discounting at 8 percent.

million with MISO receiving approximately $12 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, both MISO and SPP's B/C ratio is 3.58.

SPP prefers the regional solution, Northeast – Charlotte 2 Ohm series reactor, approved in the 2017 ITP10 to address this need. MISO's preliminary regional evaluation indicates that the Crosstown to Blue Valley 161 kV line would likely not pass MISO's regional review.

Lacygne - Blackberry 345 kV line plus 345/161 kV transformer and Blackberry - Asbury 161 kV line

The proposed Interregional Project, Lacygne – Blackberry 345 kV line plus 345/161 kV transformer and Blackberry – Asbury 161 kV, is a new transmission project in Missouri (Figure 8.2-4). This project has an expected in-service date of 2021.

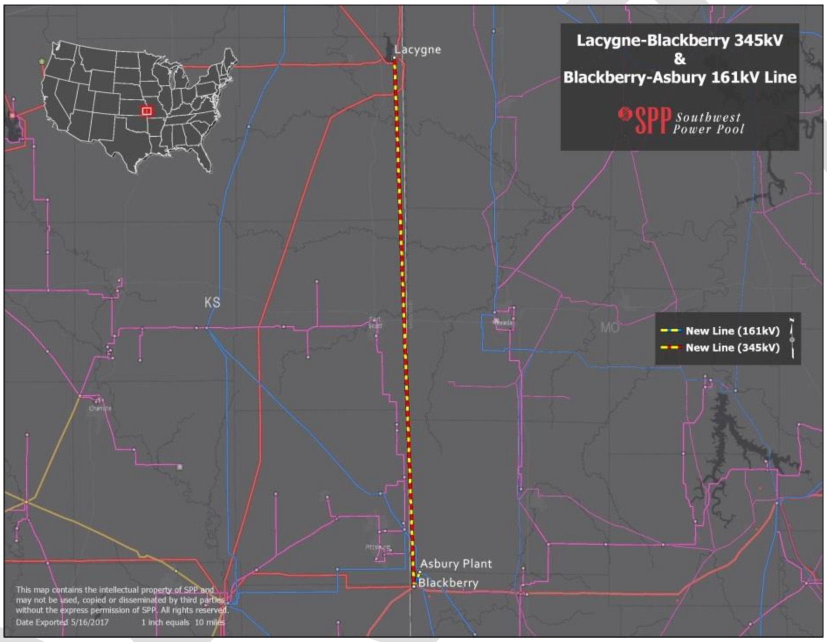


Figure 8.2-4: Lacygne - Blackberry 345 kV line plus 345/161 kV transformer and Blackberry - Asbury 161 kV line

This project was proposed to relieve congestion on the Neosho - Riverton 161 kV flowgate. MISO and SPP's analyses show that relieving the congestion on this flowgate provides benefit to both MISO and SPP. This project was calculated to relieve 69% of the congestion on the Neosho - Riverton 161 kV flowgate.

SPP estimated an E&C cost of approximately $153.65 million[61] with an assumed in-service date of 2021. The $153.65 million E&C cost results in a 20-year present value of $187.75 million[62]. MISO and SPP's 20-year benefit analysis shows that over the first 20 years of the project's life, MISO and SPP are estimated to receive $193.83 million[63] in APC benefit resulting in a 20-year B/C ratio of 1.03. Of the $193.83 million of APC benefit, SPP is estimated to receive approximately $184 million with MISO

[61] 2016 dollars
[62] The 20-year present value cost number is calculated using SPP's 18.16 percent NPCC, factoring in depreciation, and discounting at 8 percent.
[63] The 20-year present value benefit number is calculated using a discount rate of 8 percent.

receiving approximately $10 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, both MISO and SPP's B/C ratio is 1.03.

SPP and MISO agreed this project was marginally passing several of the JOA criteria for Interregional Projects. The B/C ratio of 1.03 would have likely fallen below the desired 1.0 B/C ratio with any cost increase to the project. The project also only attributes 5 percent of the estimated APC benefit to the MISO region. SPP and MISO agreed to not recommend this project to the regional review. Additionally, SPP prefers the regional solution, Upgrade Butler – Altoona and Neosho – Riverton Terminals, approved in the 2017 ITP10 to address this need. Additionally, Lacygne – Blackberry 345 kV line plus 345/161 kV transformer was evaluated in the 2017 ITP10 and did not pass the screening process.

James River - Brookline 345 kV line plus 345/161 kV transformer

The proposed Interregional Project, James River - Brookline 345 kV line plus 345/161 kV transformer, is a new 11-mile transmission project in Missouri (Figure 8.2-5). This project has an expected in-service date of 2021.

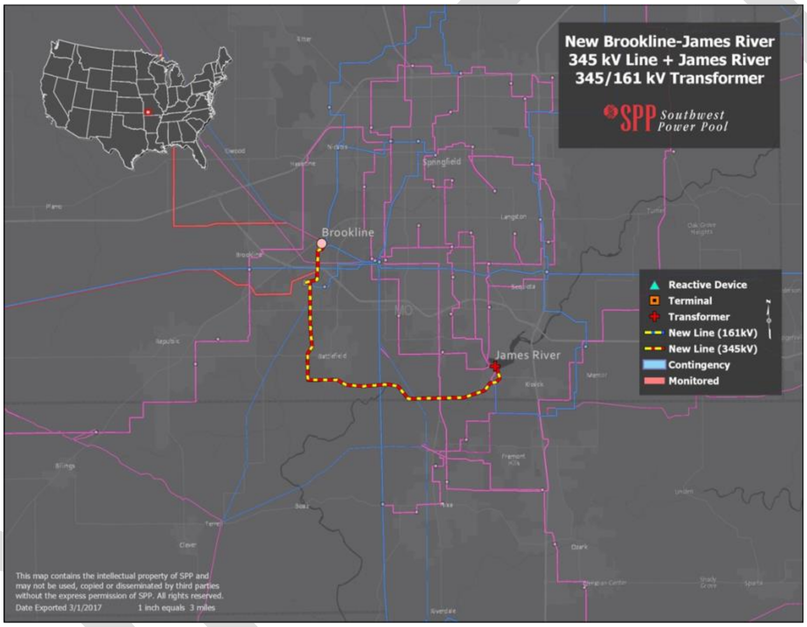


Figure 8.2-5: James River - Brookline 345 kV line plus 345/161 kV transformer

This project was proposed to relieve congestion on the Brookline 345/161 kV transformer. MISO and SPP's analyses show that relieving the congestion on this transformer provides benefit to both MISO and SPP. This project was calculated to completely mitigate the congestion on the Brookline 345/161 kV transformer.

SPP estimated an E&C cost of approximately $25 million[64] with an assumed in-service date of 2021. The $25 million E&C cost results in a 20-year present value of $30.54 million[65]. MISO and SPP's 20-year benefit analysis shows that over the first 20 years of the project's life, MISO and SPP are estimated to receive $62.49 million[66] in APC benefit resulting in a 20-year B/C ratio of 2.05. Of the $62.49 million of

[64] 2016 dollars
[65] The 20-year present value cost number is calculated using SPP's 18.16 percent NPCC, factoring in depreciation, and discounting at 8 percent.
[66] The 20-year present value benefit number is calculated using a discount rate of 8 percent.

APC benefit SPP is estimated to receive approximately $50 million with MISO receiving $12.5 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, both MISO and SPP's B/C ratio is 2.05.

SPP prefers the regional solution, Morgan Transformer Project, approved in the 2017 ITP10 and SPP-AECI JCSP to address this need, and MISO's preliminary regional evaluation indicates that the James River - Brookline 345 kV line plus 345/161 kV transformer would likely not pass MISO's regional review.

Reliability Assessment

As stated in the 2016 CSP scope, MISO and SPP staff reviewed proposed and approved reliability projects from their respective regional planning processes. No regional projects of one Regional Transmission Organization were identified as replacing the need for a project in the other's respective regional planning process. Additionally, the review did not indicate any regional projects that could potentially be replaced by a more efficient or cost effective Interregional Project. MISO and SPP have committed to continue to review regional reliability plans as they are approved out of each respective regional planning process.

Conclusions

Economic

Based on the results of the economic assessment as well as preliminary regional evaluation results, MISO and SPP identified one proposed project for consideration as an Interregional Project:

- I-18: Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls

This project demonstrates benefit to both MISO and SPP as well as APC benefits that exceed the costs of the project over the initial 20 years of the project life.

No-harm Test on Economic Projects

Interregional Projects identified to address congestion were evaluated to ensure they do not create reliability issues. The evaluation could have resulted in the modification of the Interregional Project or identification of additional interregional facilities that are needed to mitigate the projected reliability issue.

SPP utilized the its most recent and updated powerflow models to test the Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls for adverse reliability impacts. SPP 2017 ITP near-term supplemental models as well as the 2017 ITP near-term final reliability assessment models, which included the 2017 ITP near-term approved projects, were used for the analysis. All 15 combinations of seasons and model years were tested, and no reliability violations were caused by the addition of the project.

MISO reviewed MTEP16 for any harmful impact of project I-18. Steady-state reliability analysis was performed to check for overloads and voltages within bandwidths. MISO performed steady state analysis on the Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls. Five models were used to analyze pre- and post-project system conditions to compare impacts. MISO simulated contingencies from the area provided by Transmission Planners and new contingencies representing the project. Results were analyzed for new inabilities for the transmission system to reliably meet violations and large impacts to existing issues.

Reliability no-harm testing of project I-18 found one adverse impact of the project to the MISO or SPP[67] system for the studied conditions: an overload of the line between Lawrence to Sioux Falls due to a P6 event involving the loss of Sioux Falls – Lawrence and Split Rock – Lawrence line No. 2. Though this overload was shown in analysis, it is expected that a generator interconnection project will resolve loading issues by the end of 2017.

Interregional Cost Allocation

As outlined in the JOA, MISO and SPP have agreed to use the APC benefit metric to allocate the costs to each planning region of proposed Interregional Projects addressing primarily economic congestion.

If the recommended Interregional Project is approved by both the MISO Board of Directors and SPP Board of Directors as an Interregional Project, the costs will be allocated between MISO and SPP (Table 8.2-8).

Project	E&C Project Cost M$	MISO Cost %	SPP Cost %
Loop One Split Rock - Lawrence 115 kV Ckt into Sioux Falls	$6.15	81.48%	18.52%

Table 8.2-8: Interregional cost allocation for potential MISO-SPP interregional project

IPSAC and Joint Planning Committee Recommendation

As described in Section 9.3.3.5.1 of the JOA, a draft report detailing the work efforts completed as part of the CSP, including any proposed Interregional Projects, was provided to the IPSAC on May 25, 2017. The IPSAC had the opportunity to provide a recommendation to the JPC on the proposed Interregional Project. Taking into consideration the recommendation from the IPSAC and the combination of MISO and SPP stakeholders' votes, the JPC voted to recommend the Loop One Split Rock to Lawrence interregional project and associated interregional cost allocation, provided in this report, to both the MISO and SPP regional review processes for review and approval.

IPSAC Recommendation

The IPSAC net conference on April 24, 2017 resulted in feedback in support of the proposed Interregional Project. Multiple stakeholders expressed support for the project and there was no voiced opposition.

In addition to the IPSAC input provided during the April 24, 2017, IPSAC net conference, the MISO stakeholders' share of the IPSAC vote was conducted on April 27, 2017, at the MISO Planning Advisory Committee special meeting. The MISO portion of the IPSAC is represented by the sector representatives of the MISO Planning Advisory Committee. MISO stakeholders voted in favor of recommending the proposed Interregional Project to both the MISO and SPP regional review processes with no opposition.

The SPP stakeholders from the IPSAC conducted their vote on whether or not to move the Interregional Project to the respective regional review processes at the May 3, 2017, Seams Steering Committee meeting. The SPP stakeholders on the IPSAC include the members of the SPP Seams Steering Committee and a representative from each non-Seems Steering Committee member SPP Transmission Owner, which is interconnected with MISO's transmission system. The SPP stakeholders voted unanimously to direct the SPP portion of the JPC to vote in favor of recommending the proposed Interregional Project to both the MISO and SPP regional review processes.

[67] Due to the construction of MTEP models and timing of ERAG model construction, facilities in the SPP footprint have a one-year delay of representation in these models. For a more accurate test of no-harm, SPP analysis and results should be considered.

Joint Planning Committee Recommendation

The MISO and SPP representatives of the JPC met on May 15, 2017, to formally vote on the proposed Interregional Projects to be recommended for review in both the MISO and SPP regional processes. Taking into consideration the recommendation of the IPSAC, the JPC voted in favor of recommending the proposed Interregional Project for review in both the MISO and SPP regional processes.

Regional Review Process

In accordance with MISO's Tariff and BPM-020, MISO performed a regional review of the proposed I-18 Interregional Project recommended by the JPC to MISO and SPP. The regional review scope included robustness testing and sensitivity analysis consistent with efforts performed through the MCPS process to determine the extent of benefits to the customers of MISO's region. MISO also evaluated several alternative projects to determine if the I-18 Interregional Project was the most cost-effective and efficient solution. Additionally, MISO evaluated the impacts on costs due to potential unreserved use charges by SPP. The result of MISO's regional review process has concluded that although the I-18 project may be beneficial to MISO there were two alternatives that provided equal or more benefits at a much lower cost. The business cases for the I-18 interregional project were also diminished by the potential unreserved use charges by SPP. Therefore, MISO did not recommend the I-18 project for further consideration as there were two more cost-effective and efficient solutions as seen in Table 8.2-9.

Updates to the MISO-SPP CSP report will be posted on the SPP page of the MISO Interregional Coordination section under the "Planning" tab of the MISO website (www.misoenergy.org).[68]

Project Name	MISO Share of Cost ($M-2017)	Benefit-to-Cost Ratios				20-yr PV Benefit to MISO ($M-2017)			
		EF	PR	AAT	Weighted	EF	PR	AAT	Weighted
Loop One Split Rock - Lawrence 115kV Ckt into Sioux Falls (I-18)	5.14	0.1	2.1	62.4	17.1	0.4	13.6	403.7	111.0
Lawrence - Sioux Falls 115kV Terminal Equipment Upgrades (I-17)	0.51	(2.7)	20.7	782.6	211.5	(1.8)	13.4	505.3	136.6
De-energize Lawrence - Sioux Falls 115kV (Op-guide)	At no cost, this alternative is the most cost effective and efficient solution.					(2.4)	3.1	415.4	108.6

Table 8.2-9: MISO's Regional Review Results

[68] https://www.misoenergy.org/Planning/InterregionalCoordination/Pages/SouthwestPowerPoolIPSAC.aspx

8.3 MISO/ERCOT Study

A collaborative effort between MISO and the Electric Reliability Council of Texas (ERCOT) is in progress with the purpose of understanding each system's transmission issues along the seam and exploring potential unique opportunities created by joint planning.

Currently, the detailed scope of the collaborative effort is in the development stage. The study resulting from this effort will primarily be an economic evaluation, aimed at identifying solutions that can benefit both the MISO and ERCOT systems. The study will investigate various issues and identify solutions that can efficiently address them. The issues include but not limited to:

- Congestion
- Real-time operational issues
- Load pockets in both systems
- Public policy impact

Through 2017, MISO and ERCOT successfully established data exchange and communication protocols, which laid a foundation for further collaboration. MISO and ERCOT planning teams have met in person to better understand each other's planning process. A joint model is in development and testing.

8.4 Regional Transmission Overlay Study

The MISO region is undergoing a significant transformation in its resource portfolio due to a combination of factors including federal and state policies, economics and evolving technologies. If these trends continue, the transmission system may require additional flexibility that can be afforded by expanded transmission infrastructure to enable the transition in a reliable and efficient fashion. The Regional Transmission Overlay Study, as a key component of the MISO regional transmission planning process, is designed to review and to evaluate long-term transmission needs and develop conceptual overlays in positioning the transmission grid for the future. Overlay development is intended to provide a macro view of future Bulk Electric System opportunities and to shed light on future regional transmission issues and potential solutions.

The changing regional landscape and the long lead time needed to plan, approve and construct regional transmission solutions underscore the importance for MISO to take a long-term view of potential system needs periodically, in additional to annual near-term reliability and market congestion planning assessments. Long-term conceptual overlay planning of this type identifies indicative transmission overlays to help guide future system needs in accommodating the continued shift of the resource mix.

The Regional Transmission Overlay Study establishes an integrated planning approach to developing long-term indicative overlays from a regional perspective, considering both reliability needs and economic opportunities. MISO has worked with stakeholders and developed such indicative long-term overlays that could be used to support a variety of future resource mix projections for the three MTEP17 futures.

2017 overlay planning analysis is brought to conclusion with identification of indicative long-term overlays to help guide future transmission issues and potential solutions in support of changing resource mix.

Guided by insights gained from the 2017 overlay evaluation and stakeholder inputs, MISO's regional planning focus turns to additional planning analyses to further identify issues underpinning future system needs. Going forward, MISO will continue to evolve its regional planning approach to meet constantly changing reliability, economic and public policy needs, stepping towards an integrated transmission planning approach to identify the most efficient and cost-effective solutions to collectively address a suite of issues.

Study Process

The MISO scenario based planning effort starts with the development of multi-dimensional future scenarios to best manage uncertainties introduced by out-year public policy and economic conditions. MISO, in collaboration with stakeholders, developed three futures to capture the bookends of future outcomes through the MTEP17 planning cycle, providing plausible long-term views of the future resource mix. The various input assumptions and uncertainty variables defined for each policy and economic driven future form a broad set of regional resource forecasts on a least cost basis to meet regional resource adequacy requirements. Future capacity expansions include a variety of generation resource types and demand side management programs.

- **Existing Fleet:** The existing generation fleet is largely unchanged. No carbon regulations are modeled, though some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals as well as economics
- **Policy Regulations:** Carbon regulations targeting a 25 percent reduction across all aggregated unit outputs are enacted driving some coal retirements and an increase in natural gas reliance. Increased renewable additions are driven by renewable portfolio standards and goals, economics, and business practices to meet carbon regulations
- **Accelerated Alternative Technologies:** A robust economy 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. Carbon reductions targeting 35 percent across all aggregated unit outputs are achieved.

These three MTEP17 future scenarios, associated resource forecasts and siting locations were utilized to develop conceptual transmission overlays in support of a range of long-term future resource mix projections. More details of the MTEP17 futures and associated resource forecasts can be found in Section 5.2 MTEP Futures Development. Following the futures scenario development, long-term conceptual transmission overlays were developed and evaluated to serve as long-term transmission guideposts and help formulate future transmission solutions. A suite of detailed reliability and production cost analyses were performed to identify a collection of potential long-term transmission issues, considering both reliability needs and economic opportunities. Multiple AC, DC, and other available technologies were considered and evaluated to formulate indicative overlays to support a variety of future resource mix projections. Indicative overlays were developed and refined through an iterative stakeholder process by examining both reliability and economic system performance to ensure reliability and efficiency of these overlays.

The study used a stakeholder inclusive review process that allowed stakeholders to closely monitor and participate at various levels through different stakeholder forums, as described below:

- Planning Advisory Committee (PAC) served as an advisory forum to review and provide overall guidance on study scope, process and schedule
- Economic Planning Users Group (EPUG), consisting of stakeholders with high level technical and policy interests, served as the technical forum to review and provide inputs on detailed study assumptions, methodology and results, and to collectively design transmission overlays with MISO staff
- Study progress was reported regularly through PAC, and the bimonthly external Transmission Planning Status Report posted on the MISO website with email notification sent to the Planning Superlist.
- Public study page at MISO website served as the repository of all relevant study information and meeting materials for general stakeholder access
- MTEP and PROMOD FTP sites were used to post study models, input files and study results that are subject to CEII requirements

Long-term Indicative Overlay Development

The objective of the study is to conduct a multifaceted economic and reliability analysis to evaluate long-term transmission needs and develop conceptual transmission overlays, utilizing an integrated transmission design approach as illustrated in Figure 8.4-1. By identifying and combining both reliability needs and economic opportunities upfront, this integrated overlay design approach brings a holistic view of system needs to develop conceptual overlays in a more efficient and coordinated fashion. Transmission overlays are indicative long-term transmission strategies to frame and define future transmission solutions. Overlays are NOT designed for inclusion of MTEP project recommendations to the MISO Board of Directors (BOD) and subsequent construction.

The study process brings a combined view of reliability and economic drivers upfront in developing indicative overlays.

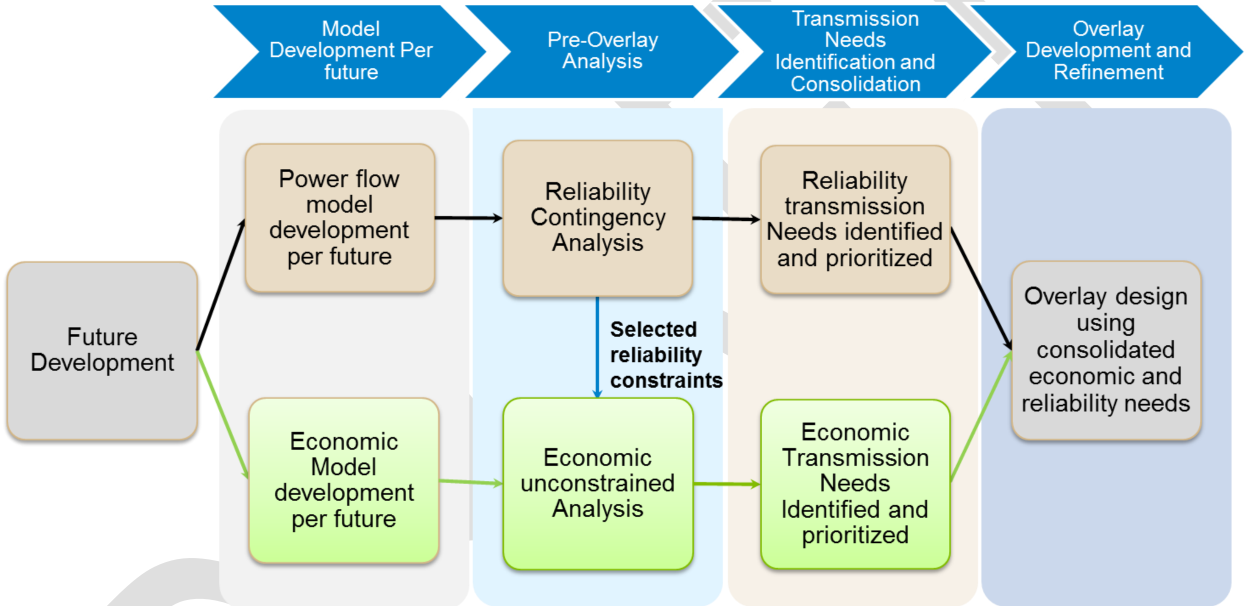


Figure 8.4-1: Integrated Transmission Overlay Design Approach

Holistic Transmission Needs Identification and Consolidation

Transmission needs identification consists of a suite of reliability contingency screening and economic unconstrained analyses to provide a holistic regional view of system needs across MISO footprint.

A detailed AC steady state contingency analysis is conducted on a series of long-term power flow cases, peak and off-peak conditions, for each defined future, consistent with applicable local and regional reliability standards. By identifying a list of thermal issues per future, this analysis demonstrates the magnitude of future system reliability needs to aid in conceptual transmission overlay design and to help determine reliability performance enabled by overlays. Top reliability indicators are identified and prioritized per model and future by severity and frequency of thermal violations. In addition, a selected number of reliability thermal constraints are added to the economic analysis to ensure a more complete set of transmission constraints are captured in production cost model simulations on the front end of the study process.

Economic transmission opportunities are determined by performing two production cost models simulations for each defined future, 1) a constrained case with existing transmission constraints; and 2) an unconstrained case with all transmission constraints removed across the MISO region. The unconstrained case establishes an optimal system and serves a bottom line of production costs, which can be used as a reference to measure the production cost performance of all the other cases. The comparison reveals the magnitude of available economic value from transmission congestion reduction and more efficient generation utilization. Differences between these two cases provide a broad set of economic information, including:

- **Top Congested flowgates or Economic Indicators** which provide future projected congestion patterns. Total shadow prices and binding hours will be produced to help rank the severity and frequency of identified congested flowgates. Top economic indicators, combined with top reliability indicators, help identify potential transmission bottlenecks and indicate locations of potential future transmission corridors.
- **Energy Sources and Sinks,** which are determined by observing the annual generation production differences for defined areas between the unconstrained and constrained cases. Source areas are export-limited areas with surplus energy and sink areas are import-limited due to transmission constraints. The direction of desired power flows is from energy sources to sinks. Linking low cost Energy Sources to high cost Energy Sinks tends to accrue the most production cost value, coupled with LMP prices.
- **Locational Marginal Prices (LMPs),** which provide congestion patterns and energy price spread across the system. Coupled with energy sources and sinks, potential locations of transmission lines are designed to link low cost source areas to high cost sink areas and bridge the largest price differences across the system to accrue the most economic value.
- **Adjusted Production Cost Savings potential** which is estimated from the total savings by taking production cost differences between the constrained and unconstrained cases, providing the magnitude of potential APC benefits that are available for a defined footprint.

All the economic information described above is used in combination to help formulate indicative long-term overlays, in conjunction with a list of selected top reliability indicators identified from reliability contingency analysis. Mapping software is used to visualize identified issues and help group reliability needs and economic opportunities based on geographic locations and similar drivers. Figures 8.4-2 to 8.4-4 illustrate the combined set of long-term economic and reliability issues identified for each of the MTEP17 future scenarios. Red represents the energy source areas where surplus energy comes from and blue signifies the energy sink areas where energy can be delivered economically. The energy sources and sinks indicate where energy would economically flow and provide a macro view of major energy transfer paths. The list of top reliability and economic limiters, represented in yellow and green respectively are also shown to help provide insights into potential locations of future transmission corridors. The indicative overlay is most valuable in addressing a combination of economic and reliability issues, linking low cost source areas to high cost sink areas and relieving the top economic and reliability limiters.

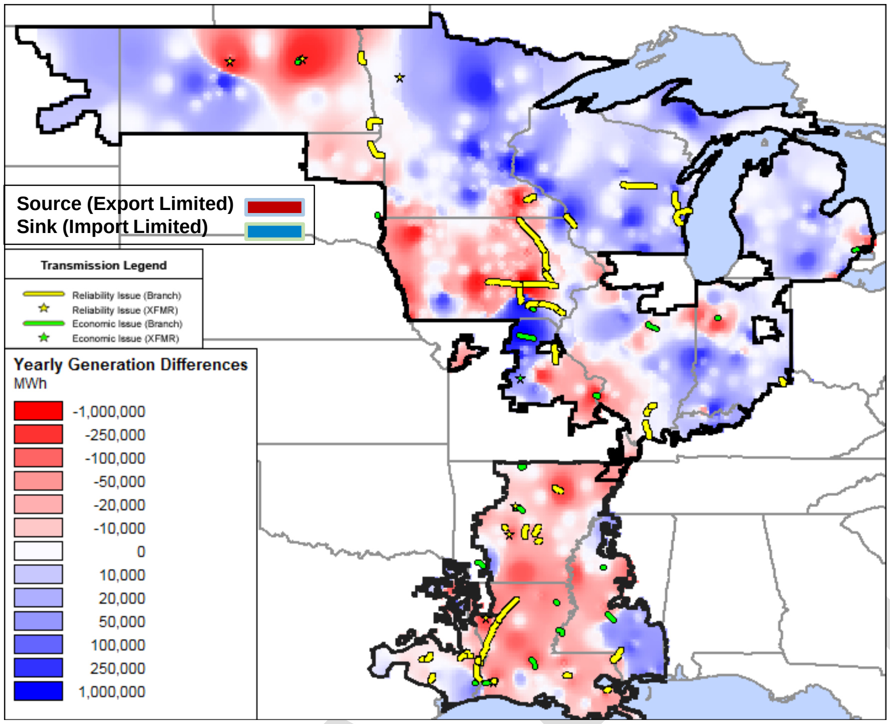


Figure 8.4-2: Long-term Transmission Needs Identified from Reliability and Economic Analyses for Accelerated Alternative Technologies Future

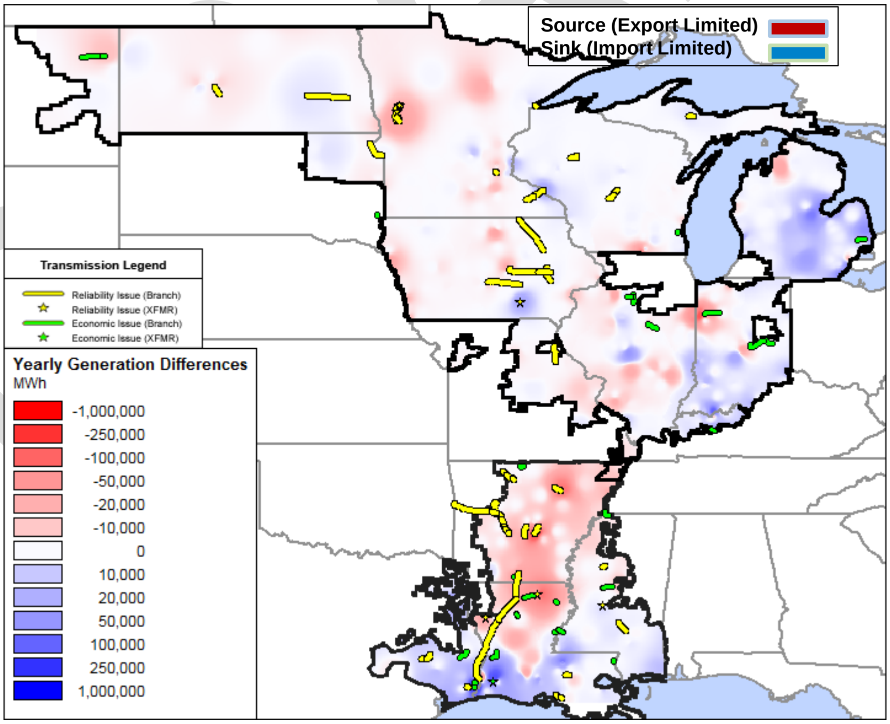


Figure 8.4-3: Long-term Transmission Needs Identified from Reliability and Economic Analyses for Existing Fleet Future

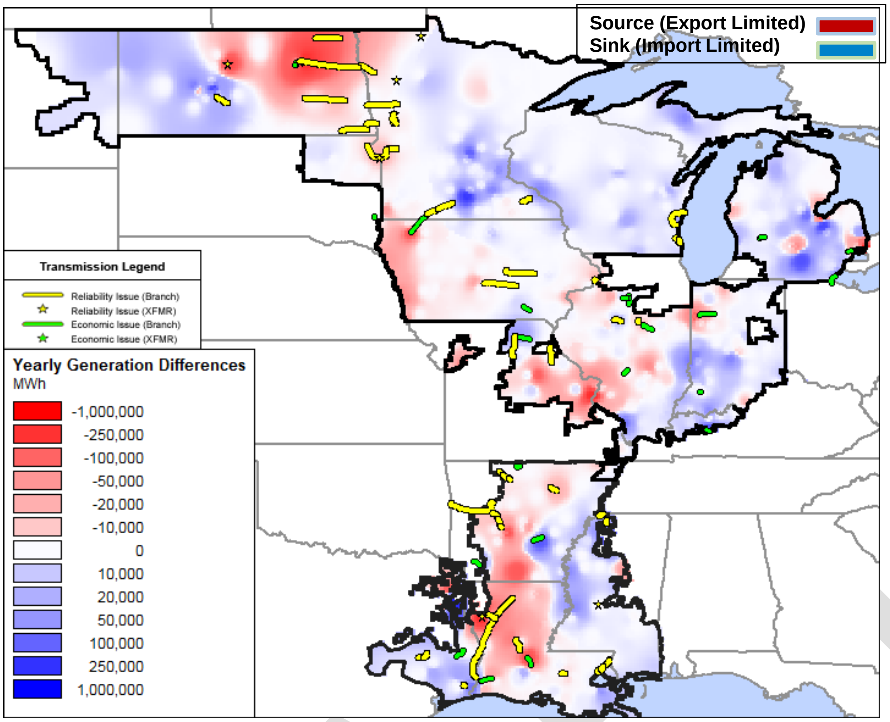


Figure 8.4-4: Long-term Transmission Needs Identified from Reliability and Economic Analyses for Policy Regulation Future

Integrated Long-term Indicative Overlay Development and Refinement

A stakeholder inclusive process through a series of Economic Planning Users Group (EPUG) overlay design workshops is used to facilitate the collaborative development of conceptual transmission overlays for each defined MTEP17 future between MISO staff and stakeholders. Preliminary overlay ideas may be proposed by stakeholders or MISO staff independently or collaboratively. Ideas proposed through past study initiatives may also be considered, where possible. Proposed overlay ideas may be combined or modified as needed to better align with the identified needs.

Long-term Overlays are developed by identifying a collection of reliability and economic issues.

In designing overlays, consideration is given to potential transmission corridors that address both reliability needs and economic opportunities from an integrated view. By prioritizing and consolidating the identified economic and reliability needs, proposed overlay ideas are integrated into preliminary regional overlays in a reliable and efficient fashion. The overlays are further refined and adjusted, through an iterative process to ensure the most efficient and cost effective long-term overlays are formulated to accommodate a variety of future resource mix scenarios, as illustrated in Figure 8.4-5. The refinement considerations include, but are not limited to, utilization of new transmission overlay elements, effectiveness in addressing identified system needs, realization of synergistic benefits by relieving a group of issues, consolidation of aging transmission infrastructure replacement, etc.

A suite of reliability and economic contingency analyses are performed to identify overlay related events for inclusion of power flow and economic models, capturing additional system impacts caused by indicative overlays. To facilitate indicative overlay refinement, the set of identified issues are broken down by sub-region and/or focus areas to identify and evaluate effectiveness of potential overlay idea alternatives or a group of overlay idea combinations with both economic and reliability analyses.

During the iterative overlay refinement process, overlay ideas may be removed if transmission elements are under-utilized with no significant loadings, added or modified if the identified issues are not sufficiently addressed, or combined to address a group of issues synergistically. A combination of economic and reliability performance indicators are utilized to determine the performance of overlay idea alternatives in addressing system needs, such as the number of elements mitigated and aggravated, total % of congestion relieved, etc. A regional overlay will then be further refined by selecting and combining top performing refined overlay idea alternatives in each sub-region/focused area.

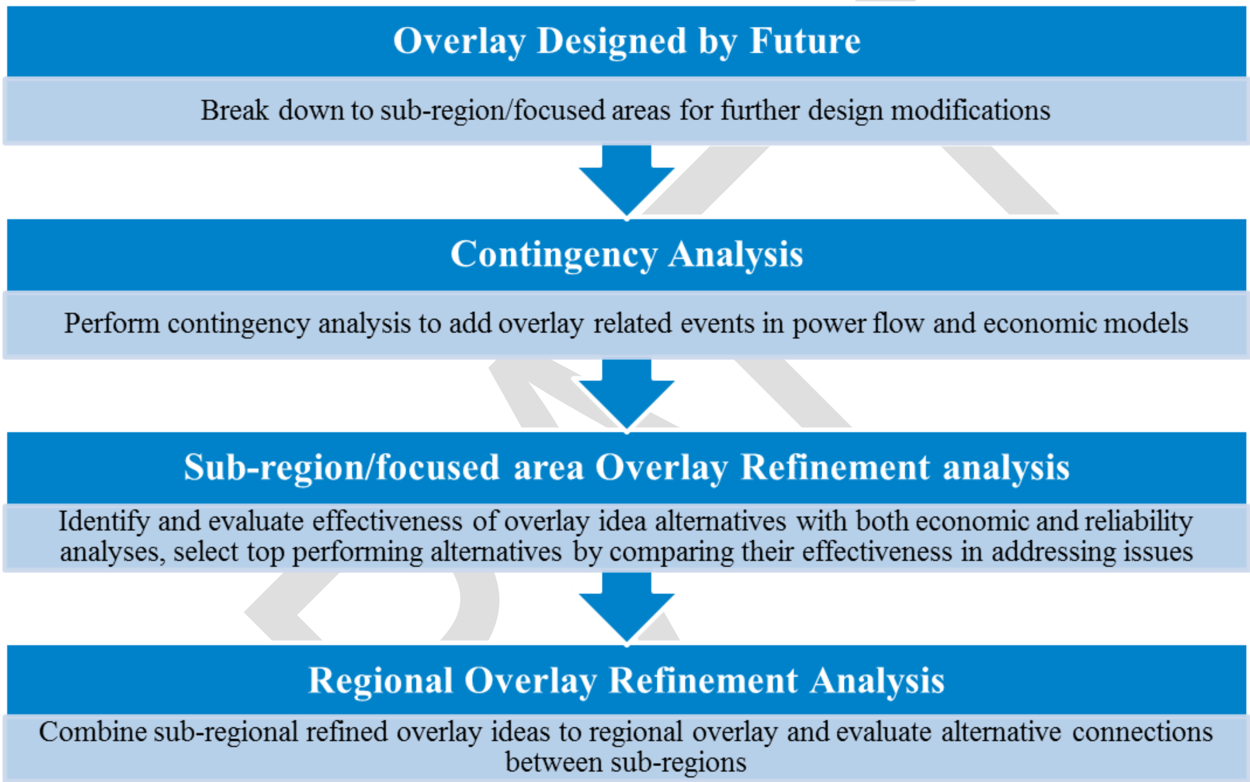


Figure 8.4-5: Indicative Overlay Refinement Process

With extensive stakeholder collaboration taking place under the Economic Planning Users Group (EPUG) overlay design workshops, three distinct long-term indicative overlays have been developed to accommodate a variety of future resource mix projections as defined in the MTEP17 futures. The MTEP17 futures model a range of generation fleet changes, from a stalled generation fleet change in the Existing Fleet Future, a continuation of historical fleet change trends in the Policy Regulations Future, to a future consisting of accelerated fleet changes with a higher level of renewables and demand side technologies above historical trends. Following the same trend as observed in future resource mix projections, the Existing Fleet overlay shows minimal expansion of the existing backbone system across the footprint, the Policy Regulations Future overlay shows moderate expansion of transmission with both AC and DC technologies utilized, and the Accelerated Advanced Technologies Future overlay has the most aggressive transmission expansion with a large conceptual 765kV network hub to enable energy transfers between the North and Central regions and two additional 765kV lines to strengthen the North and South connection. Figures 8.4-6 to 8.4-8 depict these three indicative overlays by Future. Detailed Indicative overlay facilities are tabulated in Appendix E3.

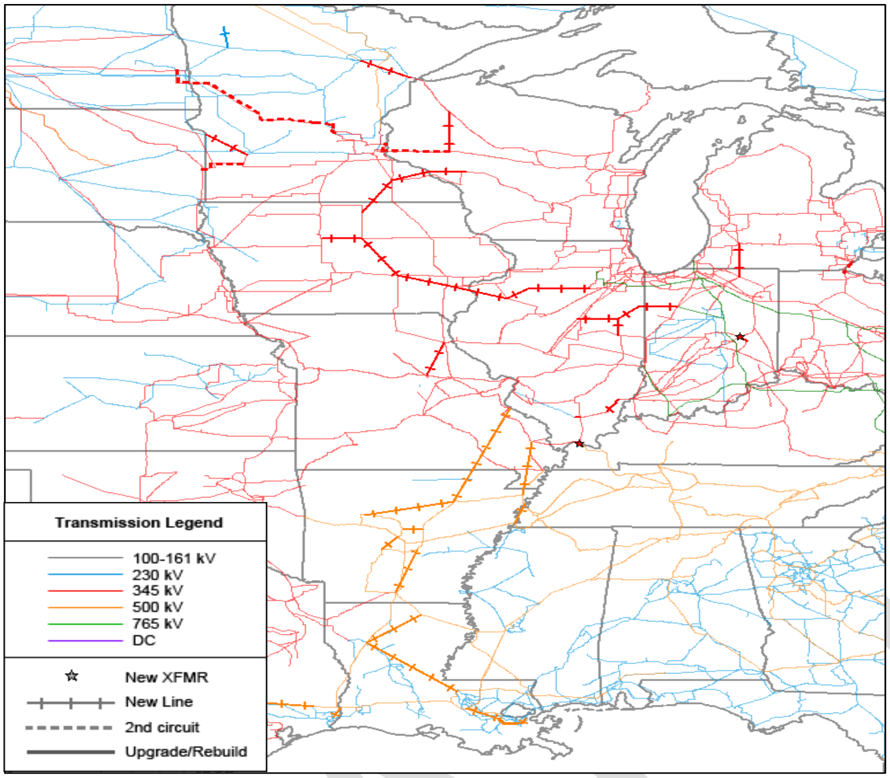


Figure 8.4-4: Indicative Overlay for Existing Fleet Future

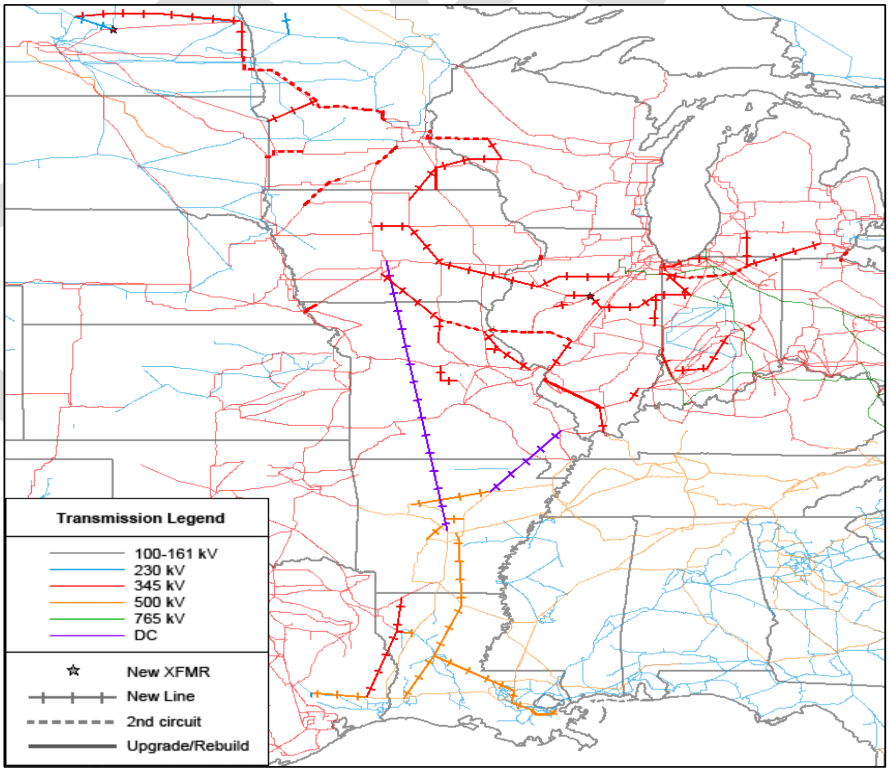


Figure 8.4-5: Indicative Overlay for Policy Regulations Future

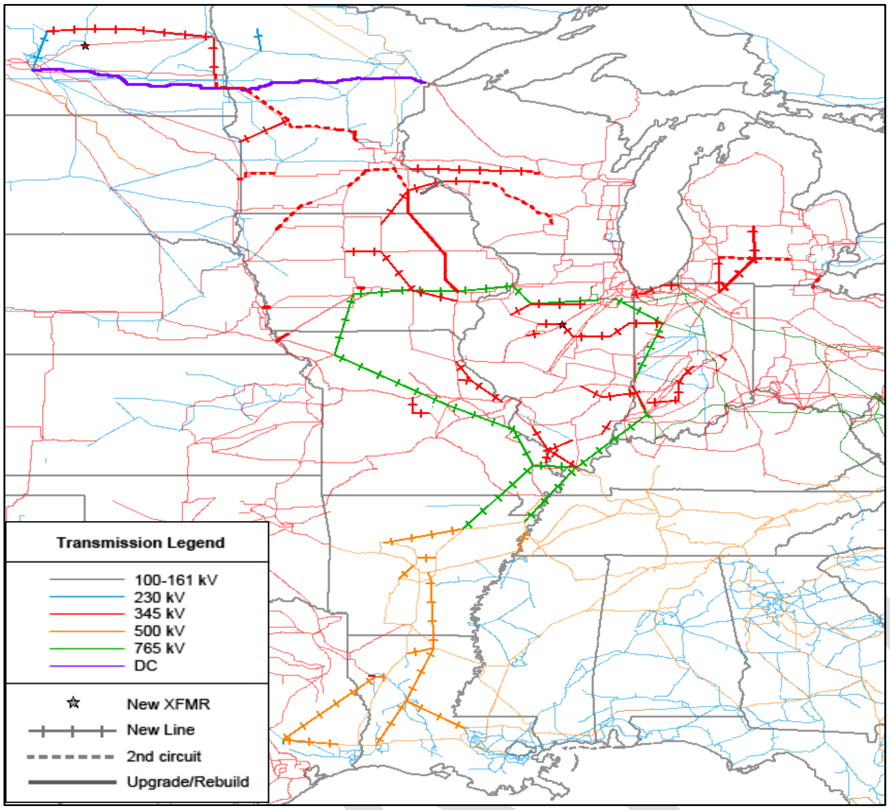


Figure 8.4-6: Indicative Overlay for Accelerated Advanced Technologies Future

System performance of three indicative overlays is demonstrated in Table 8.4-1, using a set of economic and reliability performance indicators. Additional analysis is needed to further identify issues and determine the effectiveness of these indicative overlays.

Category	Performance Indicators	EF Overlay	PR Overlay	AAT Overlay
Reliability[1]	# of Elements Mitigated	214	393	287
	# of Elements Aggravated	16	35	32
Economic[2]	Total Congestion Relieved (%)	69%	64%	50%
	# of Mitigated Issues	29	52	85
	# of Helped Issues	4	3	15
	# of Worsened Issues	1	8	16
	# of New Issues	3	5	20

Table 8.4-1: Indicative Overlay Performance Indicators for Reliability and Economic Issues[69,2]

[69] Mitigated – Branch loading is < 100% and reduced by at least 3% for all contingencies in all cases. Aggravated – branch loading is 100% and increased by at least 3% for at least one contingency in one case.
[2] A Shadow Price (SP) cutoff of 25 k$/MWh is used. Mitigated issues drop below the cutoff after overlay. Helped issues see a 50% or more drop in SP, but are still above the cutoff. Worsened issues see a 20% or greater increase in SP.

Development of Long-term Planning Models and Assumptions

A suite of planning models are required to perform this long-term overlay planning study and will be developed for each of the MTEP17 future scenarios, including:

- PSS®E reliability models to evaluate system reliability requirements with the transmission thermal limitations and required voltage levels at different points of the system,
- Production cost models PROMOD IV® to support development and economic assessment of long-term overlays,
- Electric Generation Expansion Analysis System (EGEAS) to identify future generation capacity expansions to meet resource adequacy requirements.

Power Flow Models

A set of 15 year out summer peak and shoulder peak power flow models is developed for each future, representing various system conditions in the long-term planning horizon. The MTEP16 10 year out summer peak power flow models, which were developed and reviewed through regular MTEP model building process, are used as the basis. To develop future based power flow models, the MTEP16 10 year out summer peak models are updated with the set of forecasted generation additions, retirements and load projections defined by each MTEP17 future scenarios. Future transmission facilities that are approved and are targeted for approval in the MTEP16 planning are included in the base models.

A regional merit order dispatch (RMD) is applied to power flow models, reflective of an optimal market dispatch. MTEP16 NERC Category P1, P2, P4, P5, and P7 events for facilities greater than 200kV or generator unit greater than 300 MVA will be used for reliability analyses. All elements greater than 100 kV are monitored for overlay design and evaluation.

Production Cost Models

15 year out PROMOD models are developed for a set of futures, consistent with defined future assumptions on generation, fuel prices, demand and energy, carbon cost. The transmission topology is sourced from the stakeholder-reviewed MTEP16 2026 summer peak power flow model.

Production cost models use an “event file” to capture a set of transmission constraints to ensure the system reliability is maintained by performing hourly security constrained unit commitment and economic dispatch. The event file is developed based on the latest MISO Book of Flowgates and NERC Book of Flowgates and subsequently updated to incorporate ratings and configuration changes from concurrent studies and stakeholder review process. As appropriate, a selected number of reliability thermal constraints identified through contingency screening analysis is added to ensure the most severe limiters of the transmission system are captured in the event file.

Indicative Overlay Facility Modeling Assumptions

Generic data, representative of typical industry practice, are used to model conceptual overlay transmission line facilities and substation transformers. The standard ratings for terminal equipment and a minimum value for the conductor are established based on the default ratings tables described in MISO BPM29 Minimum Project Requirements for Competitive Transmission Projects, which represents a proxy for typical standard ratings employed within the industry. For each kV level, a conductor size, type, and bundling configuration that meets or exceeds the BPM 29 default rating table values is selected based on IEEE 738 analysis. For each kV level, a high-level structure design is then selected to estimate the GMD. PLS CADD is used to determine per mile values for positive sequence series resistance, series reactance, and shunt susceptance in ohms, ohms, and mhos respectively based on selected proxy conductors, bundling configuration, and phase spacing associated with the high-level design. Per mile ohm and mho values are then converted to per mile per unit values on a 100 MVA based to be applied in power flow and production cost models. Generic data for transmission lines is applied to estimated line mileage with a 20% adder. Same ratings and impedance data as the existing transmission circuit are used to add additional transmission circuits on spare positions of existing structures at the same kV level. For substation transformers, existing transformers of a similar size from the model are used to estimate impedances to ensure the nameplate percent impedance within the range of 5%-12%. BPM 29 bus configuration tables are used as a guideline to develop contingencies for new substation facilities for reliability analysis.

	230 kV Single Circuit	345 kV Single Circuit	345 kV Double Circuit	500 kV Single Circuit	765 kV Single Circuit
Selected Conductor	1-795 ACSS	2-795 ACSS	2-795 ACSS	3-954 ACSR	4-954 ACSR
Structure Type	Steel Monopole w/Davit Arms	Steel Monopole w/Davit Arms	Steel Monopole w/Davit Arms	Steel Lattice Tower Delta	Steel Lattice Tower Horizontal
GMD (Feet)	21.13	30.68	31.65	41.98	56.10
R1 (pu per mile @ 100 MVA)	0.000208	0.000046	0.000046	0.000013	0.000004
X1 (pu per mile @ 100 MVA)	0.001454	0.000496	0.000499	0.000220	0.000092
B1 (pu per mile @ 100 MVA)	0.002914	0.008441	0.008387	0.018890	0.045039
SIL (MW)	141.6	412.6	409.9	926.0	2211.7
Summer Emergency Rating (A)	1200.0	3000.0	3000.0	3000.0	4000.0
Summer Normal Rating (A)	1200.0	2652.6	2652.6	2353.9	3138.6
Winter Emergency Rating (A)	1200.0	3000.0	3000.0	3000.0	4000.0
Winter Normal Rating (A)	1200.0	3000.0	3000.0	3000.0	4000.0

Table 8.4-2: High-Level Generic Transmission Line Designs in Overlay Development

Going Forward

The Regional Transmission Overlay Study process establishes an integrated planning approach to developing long-term indicative overlays from a regional perspective, considering both reliability needs and economic opportunities. The 2017 overlay analysis offers transmission owners and developers, regulators, and stakeholder's valuable insights by providing long-term guideposts for identifying future transmission issues and potential solutions.

The 2017 overlay analysis offers valuable insights by providing long-term guideposts for identifying future transmission issues and potential solutions.

Knowledge gained from the 2017 overlay analysis that MISO can build upon as it works with its stakeholders to plan for future grid includes:

- The overlay planning is one of many valuable planning tools in positioning grid for the future as the region navigates the changing energy landscape. Periodic overlay planning, combined with annual reliability and economic planning assessments, helps ensure overall flexibility and robustness of the overall MTEP planning process.
- While overlays are designed to be indicative long-term strategies to guide future analyses, it is important to note a set of common overlay elements demonstrating robustness and compatibility with all three long-term overlay strategies. These common transmission elements, along with similar potential solutions identified in other planning studies, can serve as valuable inputs to inform potential transmission decisions in future planning cycles. Common transmission issues identified in all of the indicative overlays also provide insightful information to help frame future planning studies to further investigate these potential issues.
- As the amount of future renewable generation with a high concentration in the west region grows from the Existing Fleet Future to the Policy Regulations Future to the Accelerated Alternative Technologies Future, increased west to east flows and aggravated reliability and economic issues in the North and Central regions, are observed. Without new transmission, future renewable generation may be highly curtailed. As modeled in the MTEP17 futures, high levels of renewable resources in the west region may be integrated if supported by increased system ability to collect and deliver concentrated renewable energy in the area.
- The 2017 overlay analysis demonstrates the value of an integrated planning approach to develop indicative overlays in a more efficient and coordinated fashion, addressing a combined set of economic and reliability issues. Going forward, MISO will continue to evolve its regional planning approach to meet constantly changing reliability, economic and public policy needs, stepping towards an integrated transmission planning approach to identify the most efficient and cost-effective solutions to collectively address a suite of issues.

Guided by insights gained from the 2017 overlay evaluation and stakeholder inputs, MISO's regional planning focus turns to additional planning analyses to further identify issues underpinning future system needs. These potential future study areas include renewable integration impact assessment, grid resilience, northwest stability, Distributed Energy Resources, generator retirement, and seams coordination. Any and all such discussions and related studies are intended to provide foundational information that inform stakeholders and MISO about potential issues and solutions and shape future discussions. The complexity of issues identified and stakeholder inputs will provide guidance on the timeline and scope of these potential analyses.

Multiple issues require further investigation through future MTEP planning cycles to better understand MISO members' needs

- **Renewable Integration Impact Assessment:** MISO has initiated discussions with stakeholder to look at different inflection points of renewable integration, both wind and solar, considering the operational, system steady state, stability, and resource adequacy implications are at each point.
- **Northwest Stability:** MISO west region has been stressed with a notably large amount renewables currently connected to the system. The continued growth in the generator queue and increased level of baseload retirement will further aggravate the stability issues on the west region, which may merit further exploration to understand system impact over the long term.

- **Grid Resilience:** The increasing reliance on continuous electric supply coupled with large natural disasters, cyber or physical attack, and on-going structural change of the grid indicates a broad conversation needs to occur to answer the questions around what resilience is, and how to evaluate and quantify impacts due to extreme events and ongoing changes, in collaboration with stakeholders.
- **Distributed Energy Resources:** MISO region could see a considerably higher penetration of DERs. One area where challenges may be presented is developing appropriate models for DER and evaluating how DERs are affecting the reliability of the regional bulk electric system given the limited visibility into distributed energy resources that are interconnected at the retail level.
- **Generation Retirement:** Baseload retirements continue within the MISO footprint, MISO has conducted generation retirement sensitivity analysis as part of MTEP17 and will continue looking into ways to evaluate system impacts due to retirement through effective scenario analysis.
- **Seams Coordination:** Generation portfolios for MISO and neighboring regions have been evolving for some time now and are expected to continue going forward, MISO and its neighbors continue to explore and look for best solutions in support of each respective regional portfolio evolution through interregional joint coordinated studies.

Book 4 / Regional Energy Information

Section 9: Regional Energy Information

9.1 MISO Overview

MISO is a not-for-profit, member-based organization that administers wholesale electricity and ancillary services markets. MISO provides customers a wide array of services including reliable system operations; transparent energy and ancillary service prices; open access to markets; and system planning for long-term reliability, efficiency and to meet public policy needs.

MISO has 48 Transmission Owner members with more than $34.5 billion in transmission assets under MISO's functional control. MISO has 128 non-transmission owner members that contribute to the stability of the MISO markets.

MISO has 48 Transmission Owner members with more than $34.5 billion in transmission assets under MISO's functional control. MISO has 128 non-transmission owner members that contribute to the stability of the MISO markets.

The services MISO provides translate into material benefits for members and end users. The MISO's 2016 Value Proposition[70] affirms our core belief that a collective, region-wide approach to grid planning and management delivers the greatest benefits. Our landmark analysis serves as a model for other grid operators and transparently communicates the benefits in everything we do.

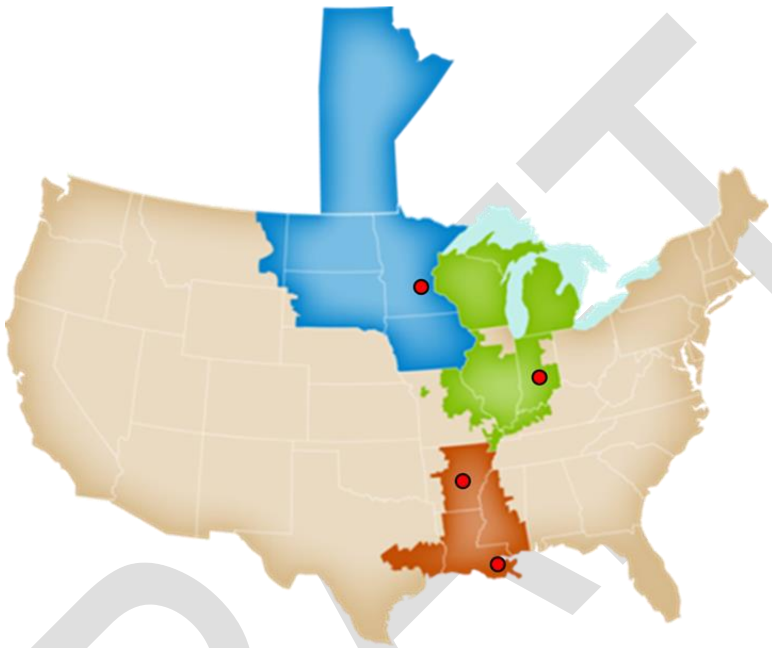
The value drivers are:

1. **Improved Reliability** - MISO's broad regional view and state-of-the-art reliability tool set enables improved reliability for the region as measured by transmission system availability.
2. **Dispatch of Energy** - MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.
3. **Regulation** - With MISO's Regulation Market, the amount of regulation required within the MISO footprint dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets.
4. **Spinning Reserves** - Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement declined, freeing low-cost capacity to meet energy requirements.
5. **Wind Integration** - MISO's regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.
6. **Compliance** - Before MISO, utilities in the MISO footprint managed their own FERC and NERC compliance. With MISO, many of these compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.
7. **Footprint Diversity** - MISO's large footprint increases the load diversity allowing for a decrease in regional planning reserve margins from 20.98 percent to 15.20 percent. This decrease delays the need to construct new capacity.
8. **Generator Availability Improvement** - MISO's wholesale power market improved power plant availability by 1.18 percent, delaying the need to construct new capacity.

[70] https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx

9. **Demand Response** - MISO enables demand response through transparent market prices and market platforms. MISO-enabled demand response delays the need to construct new capacity.
10. **MISO Cost Structure** - MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

MISO provides these services for the largest regional transmission operator geographic footprint in the U.S. MISO undertakes this mission from control centers in Carmel, Ind.; Eagan, Minn.; and Little Rock, Ark., with regional offices in Metairie, La., Little Rock, Ark. and Eagan, Minn (Figure 9.1-1).



.

Figure 9.1-1: The MISO geographic footprint and office locations

MISO by the Numbers

Generation Capacity (as of March 2017)

- 174,724 MW (market)
- 191,062 MW (reliability)[71]

Historic Summer Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 133,917 MW (reliability)[72]

Historic Winter Peak Load (set Jan. 6, 2014)

- 109,307 MW (market)
- 117,903 MW (reliability)[73]

Miles of transmission

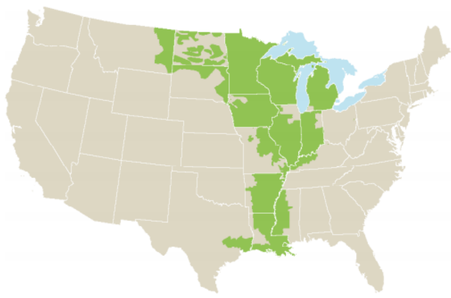
- 65,800 miles of transmission
- 383 approved new projects in MTEP16, representing $2.7 billion investment and 7,100 miles of new transmission

Markets

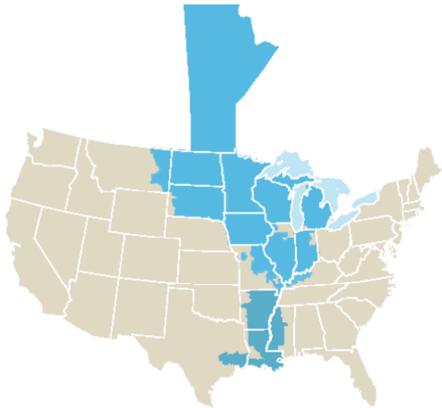
- $25.3 billion in annual gross market charges (2017)
- 2,434 pricing nodes
- 437 Market Participants serving approximately 42 million people

Renewable Integration

- 16,173 MW Registered In-Service Wind Generation Capacity
- 16,326 MW Registered Wind Generation Capacity



Market Area



Reliability Coordination Area

[71,3,4] MISO Fact Sheet

9.2 Electricity Prices

Wholesale Electric Rates

MISO operates a market for the buying and selling of wholesale electricity. The price of energy for a given hour is referred to as the Locational Marginal Price (LMP). The LMP represents the cost incurred, expressed in dollars per megawatt hour, to supply the last incremental amount of energy at a specific point on the transmission grid.

The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC) and the Marginal Loss Component (MLC). MISO uses these three components when calculating the LMP to capture not only the marginal cost of energy but also the limitations of the transmission system.

In a transmission system without congestion or losses, the LMP across the MISO footprint would be the same. In reality, the existence of transmission losses and transmission line limits result in adjustments to the cost of supplying the last incremental amount of energy. For any given hour, the MEC of the LMP is the same across the MISO footprint. However, the MLC and MCC create the difference in the hourly LMPs.

The 24-hour average day-ahead LMP at the Indiana hub over a two-week period highlights the variation in the components that make up the LMP for the first two weeks in 2017 (Figure 9.2-1). A real-time look at the MISO prices can be found on the LMP Contour Map[74] (Figure 9.2-2).

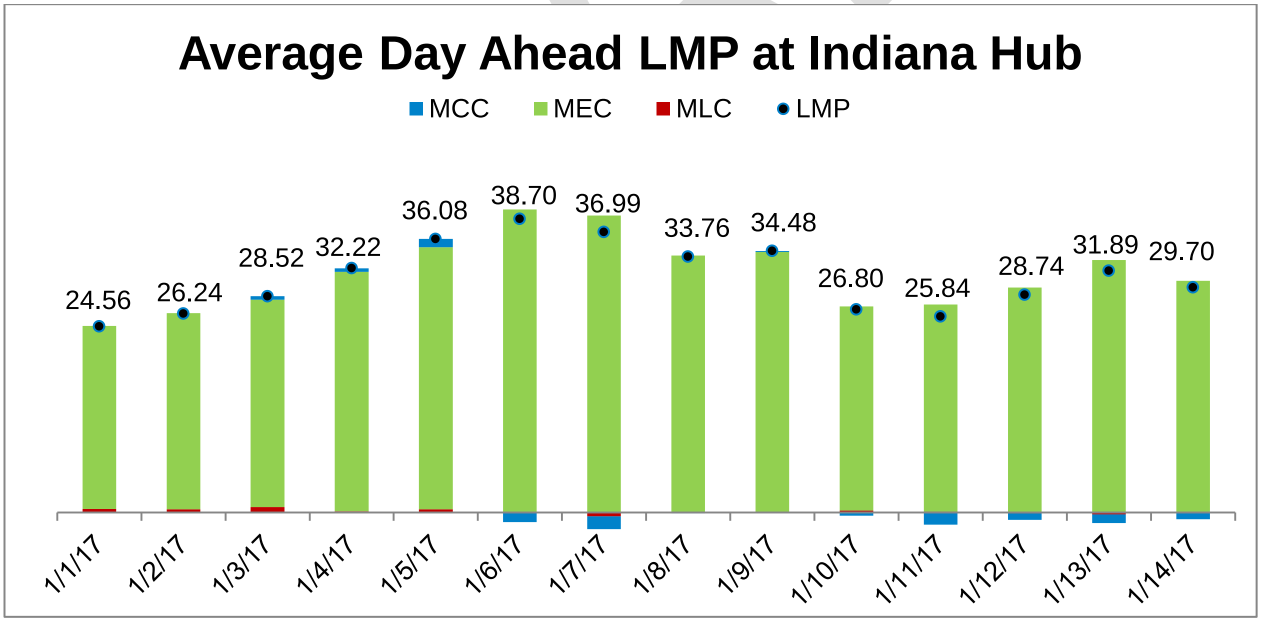


Figure 9.2-1: Average day-ahead LMP at the Indiana hub

[74] Market Analysis Monthly Operations Report: https://www.misoenergy.org/LMPContourMap/MISO_All.html

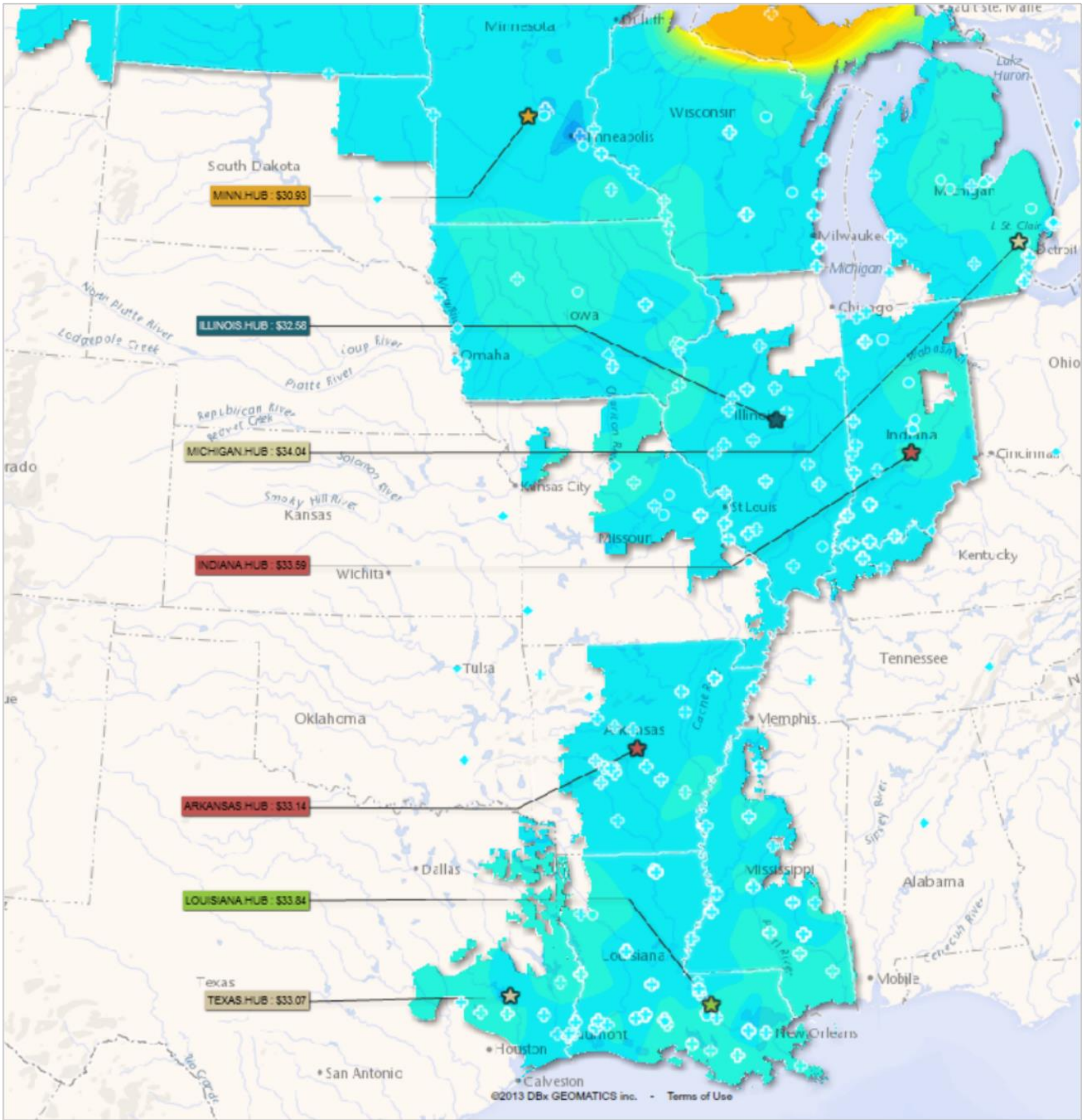


Figure 9.2-2: LMP Contour Map

Retail Electric Rates

The MISO-wide average retail rate, weighted by load in each state, for the residential, commercial and industrial sector, is 9.15 cents/kWh, about 10 percent lower than the national average of 10.10 cents/kWh. The average retail rate in cents per kWh varies by 3.7 cents/kWh per state in the MISO footprint (Figure 9.2-3).

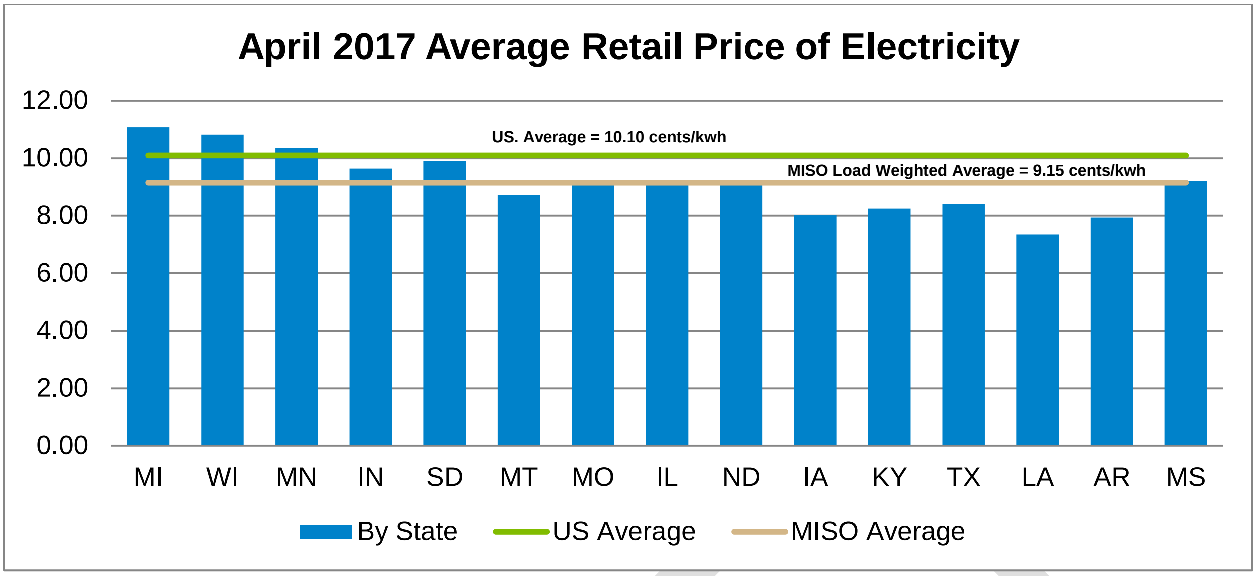


Figure 9.2-3: Average retail price of electricity per state[75]

[75] April 2017 EIA, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State

9.3 Generation Statistics

The energy resources in the MISO footprint continue to evolve. Environmental regulations, improved technologies and aging infrastructure have spurred changes in the way electricity is generated.

Fuel availability and fuel prices introduce a regional aspect into the selection of generation, not only in the past but also going forward. Planned generation additions and retirements in the U.S. from 2016 to 2020, separated by fuel type, shows the increased role natural gas and renewable energy sources will play in the future (Table 9.3-1).

	Planned Generating Capacity Changes, by Energy Source, 2016-2020					
Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)
Coal	5	752.0	93	16,943.9	-88	-16,191.9
Petroleum	22	50.3	52	1,101.2	-30	-1,050.9
Natural Gas	395	65,095.4	114	10,223.0	281	54,872.4
Other Gases	3	403.0	--	--	3	403.0
Nuclear	5	5,522.0	7	5,488.9	-2	33.1
Hydroelectric Conventional	63	950.2	24	435.1	39	515.1
Wind	184	22,603.0	6	59.2	178	22,543.8
Solar Thermal and Photovoltaic	565	14,494.5	2	1.5	563	14,493.0
Wood and Wood-Derived Fuels	4	204.5	4	45.1	--	159.4
Geothermal	7	311.9	4	90.0	3	221.9
Other Biomass	66	187.5	30	19.0	36	168.5
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	22	285.5	--	--	22	285.5
U.S. Total	1,341	110,832.8	336	34,406.9	1,005	76,425.9

Table 9.3-1: Forecasted generation capacity changes by energy source[76]

The majority of MISO North and Central regions' dispatched generation comes, historically, from coal. With the introduction of the South region in December 2013, MISO added an area where a majority of the dispatched generation comes from natural gas. The increased fuel-mix diversity from the addition of the South region helps to limit the exposure to the variability of fuel prices. This adjustment to the composition of resources contributes to MISO's goal of an economically efficient wholesale market that minimizes the cost to deliver electricity.

The increased fuel-mix diversity from the addition of the South region helps limit the exposure to the variability of fuel prices.

[76] EIA, http://www.eia.gov/electricity/annual/html/epa_04_05.html

After the integration of the South region, the percentage of generation from coal units decreases as the amount of generation from gas units increases as shown by trend lines (Figure 9.3-1).

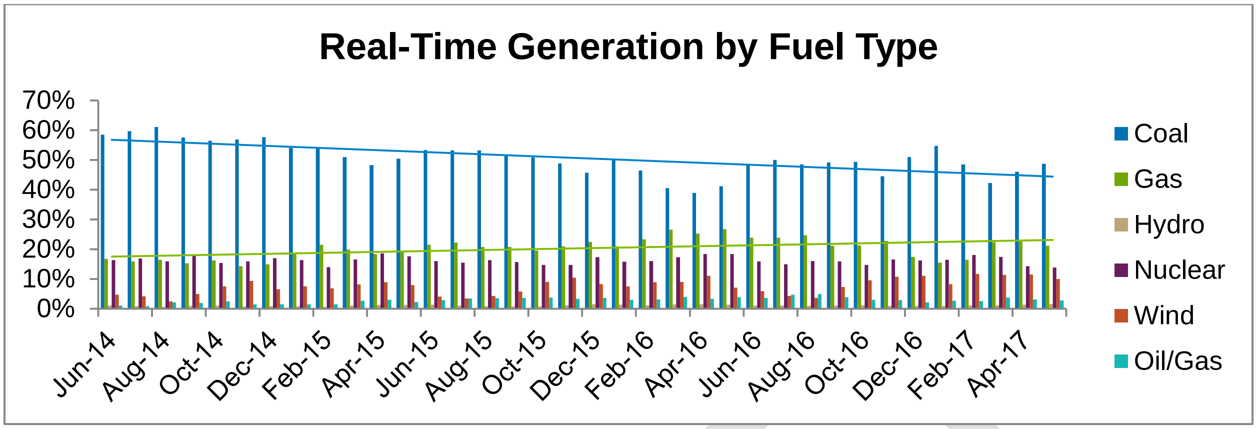
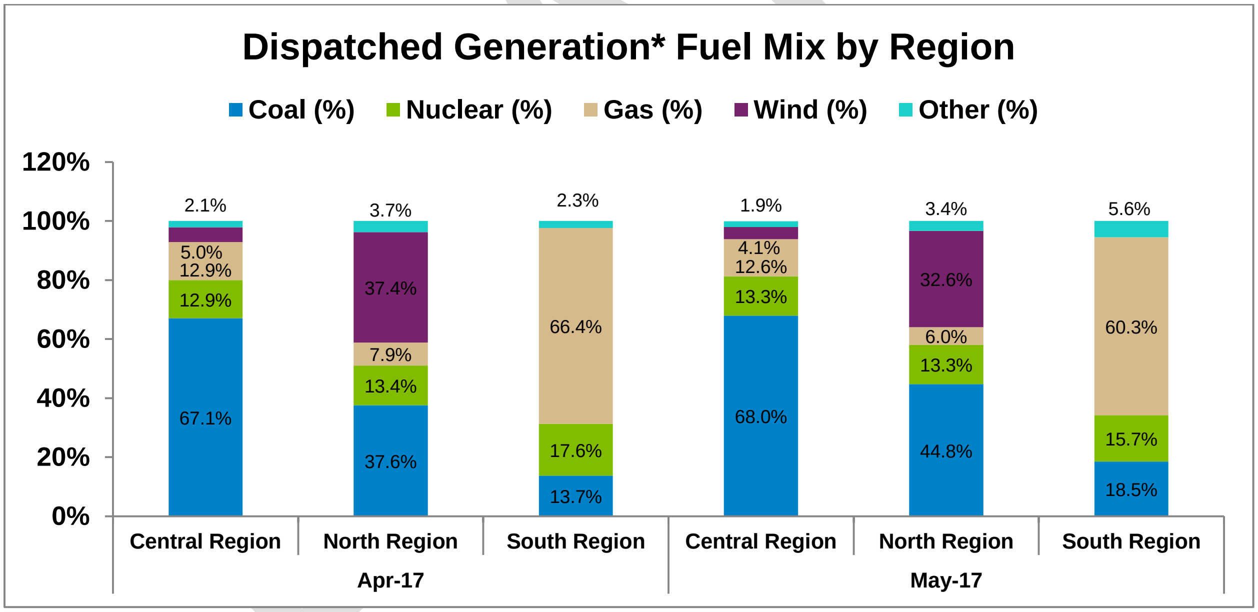


Figure 9.3-1: Real-time generation by fuel type

Different regions have different makeups in terms of generation (Figure 9.3-2). A real-time look at MISO fuel mix can be found on the [MISO Fuel Mix Chart.][77]



* Based on 5-minute unit level dispatch target

Figure 9.3-2: Dispatched generation fuel mix by region

[77] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/FuelMix.aspx

Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to use or procure renewable energy to account for a defined percentage of their retail electricity sales. Renewable portfolio goals are similar to renewable portfolio standards but are not a legally binding commitment.

Renewable portfolio standards are determined at the state level and differ based upon state-specific policy objectives (Table 9.3-2). Differences may include eligible technologies, penalties and the mechanism by which the amount of renewable energy is being tallied.

State	RPS Type	Target RPS (%)	Target Mandate (MW)	Target Year
Arkansas	None			
Illinois	Standard	25%		2025
Indiana	Goal	10%		2025
Iowa	Standard		105	2018
Kentucky	None			
Louisiana	None			
Michigan	Standard	15%		2021
Minnesota	Standard: all utilities	25%		2025
	Xcel Energy	30%		2020
	Solar standard – investor-owned utilities	1.5%		2020
Mississippi	None			
Missouri	Standard	15%		2021
Montana	Standard	15%		2015
North Dakota	Goal	15%		2015
South Dakota	Goal	10%		2015
Texas	Standard		10,000	2025
Wisconsin	Standard	10%		2015

Table 9.3-2: Renewable portfolio policy summary for states in the MISO footprint

Wind

Wind energy is the most prevalent renewable energy resource in the MISO footprint. Wind capacity in the MISO footprint has increased exponentially since the start of the energy market in 2005. Beginning with nearly 1,000 MW of installed wind, the MISO footprint now contains 16,323MW of total registered wind capacity as of May 2017.

Wind energy offers lower environmental impacts than conventional generation, contributes to renewable portfolio standards and reduces dependence on fossil fuels. Wind energy also presents a unique set of challenges. Wind energy is intermittent by nature and driven by weather conditions. Wind energy also may face unique siting challenges.

A real-time look at the average wind generation in the MISO footprint can be seen on the MISO real time wind generation graph[78].

Data collected from the MISO Monthly Market Assessment Reports[79] determines the energy contribution from wind and the percentage of total energy supplied by wind (Figure 9.3-3).

[78] https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/RealTimeWindGeneration.aspx
[79] https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/MonthlyMarketAnalysisReports.aspx

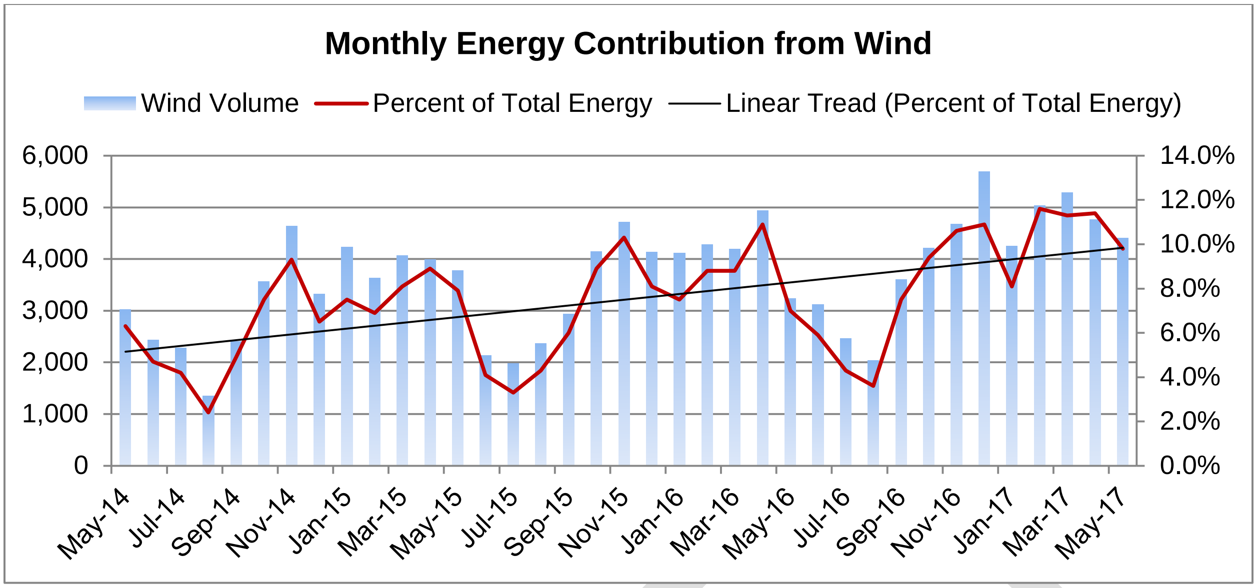


Figure 9.3-3: Monthly energy contribution from wind

Capacity factor measures how often a generator runs over a period of time. Knowing the capacity factor of a resource gives a greater sense of how much electricity is actually produced relative to the maximum the resource could produce. The graphic compares the total registered wind capacity with the actual wind output for the month. The percentage trend line helps to emphasize the variance in the capacity factor of wind resources (Figure 9.3-4).

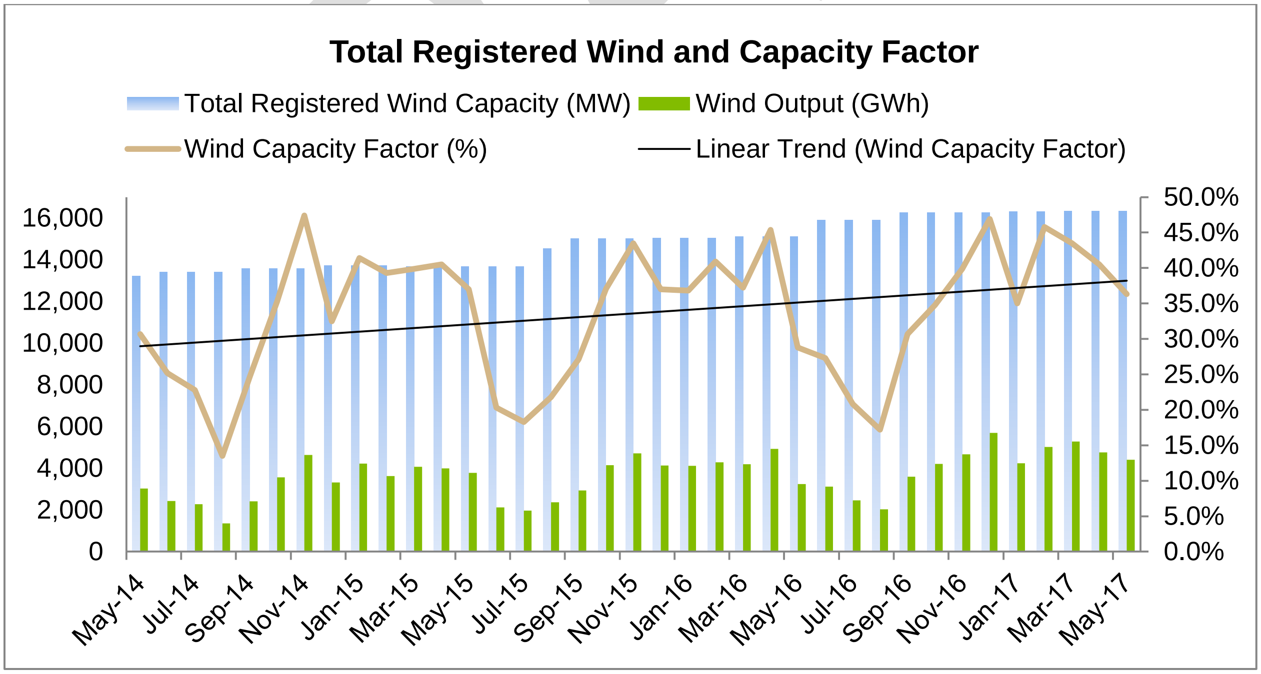


Figure 9.3-4: Total registered wind and capacity factor

9.4 Load Statistics

The withdrawal of energy from the transmission system can vary significantly based on the surrounding conditions. The amount of load on the system varies by time of day, current weather and the season. Typically, weekdays experience higher load then weekends. Summer and winter seasons have a greater demand for energy than do spring or fall.

End-Use Load

It is a challenge to develop accurate information on the composition of load data. Differences in end-use load can be seen at a footprint-wide, regional and Load-Serving Entity levels.

To keep up with changing end-use consumption, MISO relies on the data submitted to the Module E Capacity Tracking (MECT) tool. MECT data is used for all of the long-term forecasting including Long Term Reliability Assessment and Seasonal Assessment as well as to determine Planning Reserve Margins.

The Energy Information Agency (EIA) Electric Power Monthly provides information on the retail sales of electricity to the end-use customers by sector for each state in the MISO footprint (Table 9.4-1).

April 2017 - Retail Sales of Electricity to Ultimate Customers by End-Use Customer							
State	Residential		Commercial		Industrial		All Sectors
	(Million kWh)	% of total	(Million kWh)	% of total	(Million kWh)	% of total	
Arkansas	1,072	32.4%	879	26.5%	1,361	41.1%	3,313
Iowa	927	25.8%	889	24.8%	1,773	49.4%	3,589
Illinois	2,662	27.7%	3,585	37.3%	3,334	34.6%	9,622
Indiana	1,938	28.0%	1,749	25.3%	3,227	46.7%	6,916
Kentucky	1,577	30.2%	1,409	27.0%	2,241	42.9%	5,228
Louisiana	1,948	28.7%	1,868	27.5%	2,963	43.7%	6,781
Michigan	2,214	29.4%	2,995	39.7%	2,329	30.9%	7,539
Minnesota	1,528	31.1%	1,707	34.7%	1,679	34.2%	4,916
Missouri	2,009	38.3%	2,293	43.7%	939	17.9%	5,242
Mississippi	1,168	32.9%	1,050	29.5%	1,336	37.6%	3,554
Montana	374	33.5%	393	35.2%	348	31.2%	1,116
North Dakota	341	23.4%	479	32.8%	639	43.8%	1,459
South Dakota	334	37.0%	350	38.8%	218	24.1%	903
Texas	8,861	32.5%	9,862	36.2%	8,503	31.2%	27,240
Wisconsin	1,522	29.2%	1,768	33.9%	1,930	37.0%	5,220
Total	**28,475**	**30.7%**	**31,276**	**33.8%**	**32,820**	**35.4%**	**92,638**

Table 9.4-1: Retail sales of electricity to ultimate customers by end-use sector, April 2016[80]

[80] http://www.eia.gov/electricity/annual

Load

Peak load drives the amount of capacity required to maintain a reliable system. Load level variation can be attributed to various factors, including weather, economic conditions, energy efficiency, demand response and membership changes. The annual peaks, summer and winter, from 2007 through 2016, show the fluctuation (Figure 9.4-2).

Within a single year, load varies on a weekly cycle. Weekdays experience higher load. On a seasonal cycle, it also peaks during the summer with a lower peak in the winter, and with low-load periods during the spring and fall seasons (Figure 9.4-3). The Load Duration Curve shows load characteristics over time (Figure 9.4-4). Looking at all 366 days in 2016, these curves show the highest instantaneous peak load of 121,092 MW on July 22, 2016; the minimum load of 50,659 MW on April 17, 2016; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

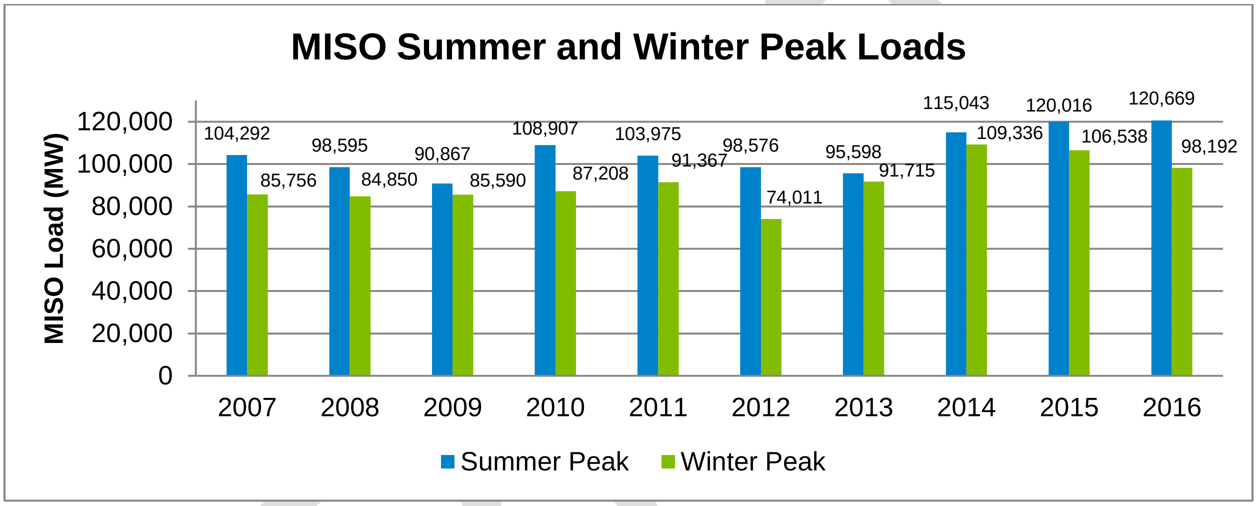


Figure 9.4-2: MISO Summer and Winter Peak Loads – 2007 through 2016[81]

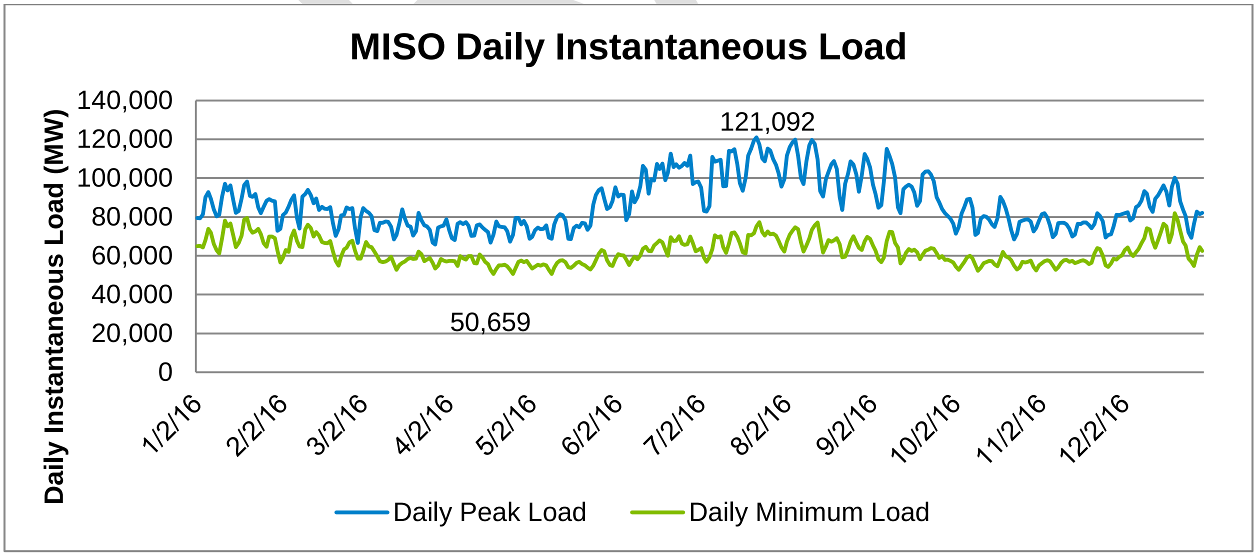


Figure 9.4-3: 2016 MISO - Daily Load[82]

[81] Source: MISO Market Data (2007-2014)

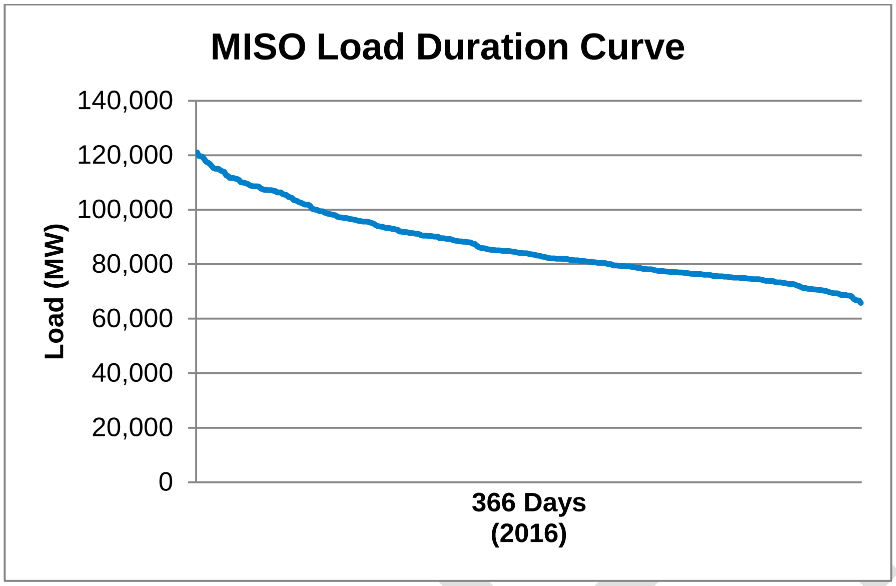


Figure 9.4-4: MISO Load Duration Curve – 2016[83]

[82] Source: MISO Market Data (2016)
[83] Source: MISO Market Data (2016)

Appendices

Most MTEP17 appendices[84] are available and accessible on the MISO public webpage. Confidential appendices, such as D2 through D8, are available on the MISO MTEP17 Planning Portal[85]. Access to the Planning Portal site requires an ID and password.

Appendix A: Projects recommended for approval
- A.1, A.2, A.3: Cost allocations
- A: MTEP17 Appendix A new projects and existing projects

Appendix B: Projects with documented need and effectiveness

Appendix D: Reliability studies analytical details with mitigation plan[86]
- Section D.1: Project justification
- Section D.2: Modeling documentation
- Section D.3: Steady state
- Section D.4: Voltage stability
- Section D.5: Transient stability
- Section D.6: Generator deliverability
- Section D.7: Contingency coverage
- Section D.8: Nuclear plant assessment
- Section D.9: Planning Horizon Transfers
- Section D.10: Short Circuit Analysis

Appendix E: Additional MTEP17 Study support
- Section E.1: Reliability planning methodology
- Section E.2: Futures development

[84] https://www.misoenergy.org/Library/Pages/Results.aspx?q=MTEP17%20Appendix
[85] https://markets.midwestiso.org/MTEP/Studies/42/Study
[86] Appendix D is available on MISO's FTP site

Acronyms in MTEP17

Acronyms in MTEP17			
AAT	Accelerated Alternative Technologies	LRR	Local Reliability Requirement
AEG	Applied Energy Group	LRZ	Local Resource Zone
AFC	Available Flowgate Capacity	LTRA	Long-Term Resource Assessment
APC	Adjusted Production Cost	LTTR	Long Term Transmission Rights
ARR	Auction Revenue Rights	MATS	Mercury and Air Toxics Standard
ASC	Available System Capacity	MATS	Mercury and Air Toxics Standards
ATRR	Annual Transmission Revenue Requirement	MCC	Marginal Congestion Component
BPM	Business Practice Manual	MCPS	Market Congestion Planning Study
BRP	Baseline Reliability Project	MEC	Marginal Energy Component
BTMG	Behind-the-Meter Generation	MEP	Market Efficiency Project
CAGR	Compound Annual Growth Rate	METC	Module E Capacity Tracking
CC	Combined Cycle	MLC	Marginal Loss Component
CCGT	Combined Cycle Gas Turbine	MMWG	Multi-Regional Modeling Working Group
CCT	Combined Cycle Turbine	MOD	Modeling, Data and Analysis (NERC)
CEII	Critical Energy Infrastructure Information	MTEP	MISO Transmission Expansion Plan
CEL	Capacity Export Limit	MVA	Mega Volt Amp
CIL	Capacity Import Limit	MVP	Multi-Value Project
CO2	Carbon Dioxide	MW	Megawatt
CPCN	Certificate of Public Convenience and Need	NAAQS	National Ambient Air Quality Standards
CPP	Clean Power Plan	NAICS	North American Industry Classification System
CROW	Control Room Operations Window	NCP	Non-Coincident Peak Demand
CSAPR	Cross-State Air Pollution Rule	NERC	North American Electric Reliability Corporation
CSP	Coordinated System Plan (MISO-SPP)	NPCC	Northeast Coordinating Council
CT	Combustion Turbine	NRIS	Network Resource Interconnection Service
DCLM	Direct Control Load Management	OASIS	Open Access Same-Time Information System
DCLM	Direct Control Load Management	OMS	Organization of MISO States
DPP	Definitive Planning Phase	OOS	Out-of-Service
DR	Demand Resources	ORCA	Operational Reliability Coordination Agreement
DSG	Amite South/Downstream of Gypsy	PAC	Planning Advisory Committee
DSM	Demand-Side Management	PJM	PJM Interconnection (RTO)
EER	Energy Efficiency Resources	PR	Policy Regulation
EERS	Energy Efficiency Resource Standard	PRA	Planning Reserve Auction
EF	Existing Fleet	PRM	Planning Reserve Margin
EI	Eastern Interconnection	PRM ICAP	Installed Capacity Planning Reserve Margin
EIA	Energy Information Agency	PRM UCAP	Unforced Capacity Planning Reserve Margin
ELCC	Effective Load Carrying Capability	PRMR	Planning Reserve Margin Requirement
EPA	Environmental Protection Agency	PSC	Planning Subcommittee
EPA	U.S. Environmental Protection Agency	PV	Photovoltaic
EPUG	Economic Planning Users Group	PV	Present Value
ERAG	Eastern Reliability Assessment Group	PY	Planning Year
ERCOT	Electric Reliability Council of Texas	RASC	Resource Advisory Sub Committee
ERIS	Energy Resource Interconnection Service	RDTL	Regional Directional Transfer Limit
FCA	Facility Construction Agreement	RE	Regional Entities
FDS	Footprint Diversity Study	RECB	Regional Expansion Criteria and Benefits
FDS	Footprint Diversity Study	RGOS	Regional Generator Outlet Study
FERC	Federal Energy Regulatory Commission	RPS	Renewable Portfolio Standard
FTR	Financial Transmission Rights	RRF	Regional Resource Forecast
GI	Generator Interconnection	RTO	Regional Transmission Owner

Acronyms in MTEP17			
GI	Generator Interconnection	RTO	Regional Transmission Owner
GIA	Generator Interconnection Agreement	RTO	Regional Transmission Organization
GIP	Generator Interconnection Project	SERC	Sub-Regional Export Constraint
GIQ	Generator Interconnection Queue	SFTP	Secure FTP Site
GIS	Geographical Information System	SIS	System Impact Study
GVTC	Generator Verification Test Capacity	SPC	System Planning Committee
GVTC TIS	Generator Verification Test Capacity - Total Interconnection Service	SPM	Subregional Planning Meeting
GW	Gigawatt	SPP	Southwest Power Pool (RTO)
IL	Interruptible Load	SSC	Seams Steering Committee
ILF	Independent Load Forecast	SSR	System Support Resource
IMM	Independent Market Monitor	SUFG	State Utility Forecasting Group
IPP	Independent Power Producer	TDSP	Transmission Delivery Service Project
IPSAC	Interregional Planning Stakeholder Advisory Committee	TMEP	Targeted Market Efficiency Project
ISD	In-Service Date	TO	Transmission Owner
JOA	Joint Operating Agreement	TPL	Transmission Planning
JPC	Joint Planning Committee (MISO-SPP)	TSR	Transmission Service Request
JRPC	Joint RTO Planning Committee	TSTF	Technical Study Task Forces
LBA	Load Balancing Area	TVA	Tennessee Valley Authority
LCR	Local Capacity Requirement	UNDA	Universal Non-disclosure Agreement
LFU	Load Forecast Uncertainty	VCE	Vibrant Clean Energy
LMP	Locational Marginal Price	VLR	Voltage and Local Reliability
LMR	Load Modifying Resource	WOTAB	West of the Atchafalaya Basin
LOLE	Loss of Load Expectation		
LOLEWG	Loss of Load Expectation Working Group		

Contributors to MTEP17

MISO would like to thank the many stakeholders who provided MTEP17 report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region. Below is a list of the MISO team who made a contribution to the MTEP17 report.

David Lucian, PE.
MISO - TAM Operations
720 City Center Drive
Carmel, IN
Office: 317-249-5627
Email: dlucian@misoenergy.org

MISO team who made a contribution to the MTEP17 Report		
Patrick Brown	Lynn Keillor	James Slegers
William Buchanan	William Kenney	Jameson T. Smith
Gretchen Carlow	Rao Konidena	Adam Solomon
Jordan Cole	Lorraine Landers	Ben Stearney
Carrie Culp	Darrin Landstrom	Erica Stillson
Jennifer Curran	John Lawhorn	Matthew Sutton
Cody Doll	David Lopez	Eric Thoms
David Duebner	David Lucian	Jason VanHuss
Joseph Dunn	Andy Miller	Jodi Walters
Matthew Ellis	Darius Monson	Ronghai Wang
Qun Gao	Jesse Moser	Joseph Wax
Arash Ghodsian	Sumeet Mudgal	Jeff Webb
Vikram Godbole	Paul Muncy	Ryan Westphal
Scott Goodwin	Josh Netherton	Kerry Wonders
Edin Habibovic	Shane O'Brien	Zheng Zhou

APPENDIX F SUBSTANTIVE COMMENTS

Planning Advisory Committee

Summary of Review and Advice to Advisory Committee and Board of Directors

MISO Transmission Expansion Plan (MTEP17)

October 18, 2017

The Planning Advisory Committee, through its Sector representatives, has reviewed the draft MTEP17 report and provided the following summary advice to the Advisory Committee and the MISO Board of Directors with respect to the MTEP report.

The written comments generally address the following areas:

- Comments on specific transmission projects
- Report content and layout

This summary by MISO staff includes substantive comments from the following stakeholders that were focused on the West of the Atchafalaya Basin (WOTAB) economic project.

- Entergy
- Xcel Energy

Additional comments and questions were submitted by the Louisiana Public Service Commission Staff concerning project cost and in-service date data contained in the MTEP Appendices A and B related to certain past and pending approved projects. By agreement with the Commission Staff, MISO will be addressing these questions directly with the Commission Staff.

In addition, editorial comments were received from stakeholders during the review process. These comments, where applicable, were incorporated into the draft MTEP17 Report.

The following stakeholders provided editorial comments:

- Ameren
- American Transmission Company (ATC)
- CMS Energy
- Entergy
- Prairie Power, Inc.
- Wisconsin Public Power Inc. (WPPI)
- Xcel Energy

Summary of Substantive Written Comments and MISO Responses

Entergy Comments Related to the WOTAB Economic Project

Entergy substantive comments submitted on this project related to assumption applied to determine generator commitments in future system planning models, and the appropriateness of the planning models used in the MISO analyses.

Unit Commitment Methodology

Entergy is concerned that the method that MISO applies in future system models to commit generation in load pockets for the purposes of Voltage and Local Reliability (VLR) assurance is flawed.

Entergy raised these comments during the open stakeholder planning process for this project and MISO responded to these comments in both stakeholder forums and written replies, most recently in responses to the September 12th 2017 Economic Planning User Group Meeting.

MISO disagrees with Entergy assertions that the methodology used to commit generation for reliability purposes is not consistent with methods the market uses for such commitments, nor that the planning approach used overstates the benefits of the proposed project.

VLR units are “pre-committed” in market operations when economic commitment of generation is insufficient to ensure local area reliability such as voltage limits or transmission loading levels. This is most often associated with load pockets that have insufficient fast start generation that can be committed in preparation for contingent conditions.

The WOTAB project addresses such a load pocket in MISO South. The generation deficiency is exacerbated as expected in future system planning models due to load growth and generation retirement assumptions. MISO’s approach in these planning models is to simulate the market commitment for VLR purposes in a manner that reflects the need for these commitments to address the combined forced outages of a transmission line and a generator. Such commitments drive the production costs in the area, and the extent to which the proposed transmission project can reduce such commitments the production cost savings are captured as a part of the overall production cost benefits of the project.

Entergy does not object to simulating these VLR commitments but rather the detailed methodology for simulating this in the planning models. MISO has compared these alternative methodologies in the past and has not found significant difference in production cost results between them. MISO supports that the approach applied in the models is reflective of the contingent conditions that cause these commitments and when applied consistently to the pre- and post-project cases provide a proper reflection of the project’s value in reducing these commitments.

Planning Models

Entergy expresses concern that the base case production cost models used in the economic benefits evaluation of Market Efficiency Projects such as the WOTAB project are not reflective of actual system conditions in future years because the models show “excessive production of emergency energy”. Emergency energy production is embedded in the production costing algorithm of these models to resolve conditions where in certain hours of the year the future model predicts that there may be constraints to serving all of the load in local areas with modeled generation. MISO had considerable dialogue with stakeholders on these models, and on this particular aspect of the models. MISO has provided both verbal and written responses to Entergy comments on this topic.

All models are vetted with stakeholders and future system load and generation assumptions are based on the Futures (future system state assumptions) developed through extensive discussion with the Planning Advisory Committee. The emergency energy produced in the models reflects base conditions consistent with these vetted future states. This is consistent with models that have been used historically to value transmission expansion projects. MISO believes that, similar to the VLR modeling concerns, the consistent treatment of these future state assumptions in the pre- and post-project cases gives a reasonable reflection of the value of the project in reducing the constraint conditions giving rise to the model's need to generate this emergency energy. The project reflects a valuable solution to addressing the base case conditions predicted by the Futures.

Xcel Energy Comments Related to the WOTAB Economic Project

Xcel Energy submitted comments relative to several aspects of this project and its stakeholder process. Xcel is supportive of the process used to develop the project, and believes that the process produced an economically beneficial project. Xcel has several concerns and recommends delaying approval of the project until June of 2018. The concerns they have involve:

1) The process MISO used to update the MTEP 17 Futures' weightings which are used to evaluate the project;

2) The cost estimates associated with the line route, length, right-of-way width and whether contingency was incorporated to account for the heavy gas pipeline infrastructure in the area, and other factors;

3) Desire for more clarity on line terminations, and facilities to be eligible for competitive development compared to upgrade facilities by the incumbent;

4) Whether post hurricane Harvey reconstruction may restrict access by potential developers for due diligence assessments, and;

5) Uncertainty about the status or Right-of-First-Refusal (ROFR) laws applicable to the project in Texas

Regarding the MTEP 17 Futures, Xcel's concern centers on the fact that MISO reconsidered the weighting of Futures in early January after weights were determined via discussion earlier in 2016. MISO agrees that it is important to continue to move forward with decisions made based on robust stakeholder input and dialogue, and limits reconsideration of past decisions so that related stakeholder business and policy decisions can be made with certainty. In this instance, MISO agreed with some stakeholders that it was appropriate to revisit the MTEP 2017 weights due to the change in the presidential administration and the perceived associated increase in near-term uncertainty around federal carbon regulation and renewable tax credits. As such additional stakeholder discussion ensued in early 2017. Stakeholders most interested in reconsideration of the weights were in the MISO South sub-region, and after considerable discussion and in consideration of the market congestion planning work in progress at the time being isolated to the MISO South sub-region, MISO agreed to modify the weights for the MISO South region only. The re-weighting adjusted the weighing of the Existing Fleet, Policy Regulations, and Accelerated Alternative Technologies Futures from 31%, 43%, and 26% to 40%, 40%, and 20%, respectively. Note that the outcome of the process would not be different if the future weights would have remained the same. The overall Benefit – to – Cost ratio associated with the project was reduced by 7 percent with adjusted future weights.

Regarding the questions and comments related to the cost estimates and other design considerations, MISO appreciates these comments and concerns, and notes that any Requests for Proposal will provide sufficient technical detail of the project and its requirements.

MISO's approach to developing transmission cost estimates has been utilized since MTEP15. Each project estimate that is developed by MISO is subject to stakeholder review throughout the planning study process. The cost estimation methodology used for the WOTAB economic project is the same that was used to develop the estimates used in both Duff-Coleman EHV 345 kV project in MTEP15, and the Huntley to Wilmarth 345 kV project in MTEP16. MISO also engaged stakeholders in a robust conversation about its cost estimation methodology to be applied to the WOTAB project in early 2017. Cost estimates for this project included careful consideration both by MISO staff and external consultants of the available corridors and their characteristics. MISO included contingency in this estimate that we believe is appropriate and consistent with industry practices.

Regarding post hurricane conditions, we believe that the project should move forward. Pending approval of the project in December, Requests for Proposals will not be issued until February of 2018, with bids due six months later. We believe that this timeline will mitigate these concerns, and in any event, there will be a level playing field for all eligible developers.

Finally, regarding the status of ROFR laws in Texas, at the present we are proceeding based on the MISO tariff requirements, and the July 28, 2017 verbal ruling at the Texas Commission's open meeting, which held that Texas law does not grant an incumbent an exclusive right to build transmission within its certificated areas. As this verbal decision has not yet been memorialized by a written order, MISO continues to monitor commission actions and will adjust the project recommendation as appropriate based on the final ruling.

Verbatim Substantive Comments of Stakeholders

Entergy

Modeling of Voltage and Local Reliability Generation in MISO South Load pocket

1. ***MISO's current methodology of using N1, G1 flowgates as a proxy for expected VLR savings will, by design, over-estimate project benefits***

The N-1, G-1 flowgates approach employed by MISO does not correctly capture or reasonably estimate either the energy production or the number of hours of VLR commitments in the system. Nor does the use of N-1, G-1 flowgates provide a reasonable approximation of the changes that the construction of a proposed transmission project would cause operationally in terms of the VLR commitment rules or the congestion and the system Adjusted Production Cost ("APC"). Rather, the N-1, G-1 flowgates methodology consistently and unreasonably overstates the level of production cost savings that can be expected from a proposed project in terms of mitigating reliability-driven unit commitments. MISO's use of the N-1, G-1 flowgates approach unreasonably overstates a project's benefits.

MISO's continued failure to address Entergy's concern about the VLR modeling methodology through a scientific approach comprised of modeling the applicable VLR nomograms in both the MTEP17 base and change cases in PROMOD, and using the APC benefit resulting from the WOTAB economic project to demonstrate a reasonable and defensible basis for its "strong belief" in the N-1, G-1 flowgate methodology, is unacceptable. MISO's assertions about the efficacy of the N-1, G-1 flowgate methodology lack technical evidence. Entergy has provided robust engineering analysis that reveals MISO's current VLR modeling methodology is unreasonable and incorrect. Should MISO disagree with the analyses put forward in these and prior comments, MISO should rebut them with transparent and complete engineering analyses supported by reasonable assumptions.

2. ***MISO's methodology, as applied in the MTEP17 planning process, is misaligned with MISO's Day-Ahead and Real-Time processes.***

In its Reliability Assessment Commitment process, MISO implements the VLR unit commitments in the Day Ahead and Real Time ("DA and RT") market by enforcing VLR rules that are based on load-trigger levels in a manner that generally aligns with the VLR nomograms that have been implemented in Entergy's above analysis. The stark discrepancies between the above results and those in MISO's most recent analysis for Alternative 2 demonstrate once again that MISO's method of modeling the VLR commitments using the N-1, G-1 flowgates does not achieve a reasonable estimate of the production cost savings that can be expected to occur operationally if a given project is built.

3. ***MISO's use of N-1, G-1 contingencies in the FRAC process for reliability commitment does not produce the same market impacts as N-1, G-1 flowgates in the MTEP production cost models***

MISO has stated that the Forward Reliability Assessment Commitment ("FRAC") utilizes N-1, G-1 contingency analysis to check for reliability issues in the system resulting from such contingencies. If reliability constraints are detected in the FRAC process, MISO commits generators for the mitigation of reliability constraints (and outside the security constrained economic dispatch and commitment process) in a manner similar to the VLR commitment-rules based generator commitment described above. MISO has contended that because the FRAC process utilizes N-1, G-1 contingencies, these N-1, G-1 contingency events should therefore be included in the flowgate list of the production cost models and N-1, G-1 flowgates. However, MISO's use of the N-1, G-1 contingencies in the FRAC process to commit resources for the mitigation of reliability constraints has the same impact on congestion and system production cost as MISO's use of VLR commitment rules to ensure the commitment of resources in the market. The commitment of reliability resources in the FRAC process also takes place outside of the security constrained unit commitment and dispatch process -- and had these resources been economic, MISO would not have had to force the commitment of such resources through the FRAC process. These committed resources therefore rarely are marginal in nature (i.e., they do not impact the LMP) and have a similar depressing impact on LMPs and flowgate congestion as described in Entergy's July 14 comments regarding the impact of VLR commitment rules. The use of N-1, G-1 contingencies to force reliability unit commitment in the FRAC process does not produce the same effect on flowgate congestion (as shown in the table above) and system APC as is observed through the use of N-1, G-1 flowgates to model VLR commitments. Therefore, MISO's use of N-1, G-1 contingencies in the reliability assessment in the FRAC process does not justify the use of N-1, G-1 flowgates in the PROMOD model.

4. ***MISO's current practice of selecting N-1, G-1 flowgates for use in the MTEP PROMOD models is flawed***

In order to select the N-1, G-1 flowgates for use in the MTEP PROMOD models that are used to identify economic transmission projects, MISO relies upon a VLR study that was performed as part of the MTEP14 planning cycle. MISO has also stated that it may have used the MTEP16 reliability powerflow models with certain generating plant outages for the identification of N-1, G-1 flowgates that are used in MTEP17. However, the input assumptions and the demand/energy and resource forecast inherent in that VLR study and the MTEP16 reliability model bear no resemblance to the assumptions that have been incorporated into the MTEP17 PROMOD models. Therefore, the N-1, G-1 flowgates that might be identified using that MTEP14 VLR study and the MTEP16 reliability models are likely not suitable for the MTEP17 production cost models and likely do not result in the correct VLR generator commitments in the MTEP17 PROMOD models. More importantly, neither set of models that MISO relies upon for the identification of N-1, G-1 flowgates is able to anticipate the next set of N-1, G-1 flowgates, once the candidate economic project is in service. For instance, once any of the three WOTAB economic Alternative projects is in service, the N-1, G-1 flowgates that will require VLR commitments will move to constraints upstream of the economic project (such as the Leesville – Cooper line and the Hartburg – Layfield limiting elements), which MISO have failed to take into account in their N-1, G-1 flowgates included in their MTEP17 models. The non-inclusion of these additional N-1, G-1 flowgates and the use of the MTEP14 VLR study and the MTEP16 reliability models lead to an unreasonable set of N-1, G-1 flowgates for the modeling of VLR commitments. Based on our detailed technical review of the MISO process, it is also apparent that the selection of N1G1 flowgates is based upon outdated reliability studies and inappropriately includes some flowgates and inappropriately excludes others. This flowgate selection process thus attributes value to the proposed projects that will not be realized if upstream congestion were also considered in this inaccurate VLR simulation methodology. In summary, notwithstanding the various limitations of using the N-1, G-1 flowgates mentioned above, MISO should identify the VLR flowgates on the basis of input assumptions and resource plans that are relevant and reasonably comparable to the MTEP PROMOD models.

5. ***The "congestion" being eliminated by all of the proposed WOTAB economic project Alternatives is a modeling phenomenon that will not be replicated in real world MISO market operations.***

Significantly, there are no N-1, G-1 flowgates in the DA and RT energy markets, and MISO operationally commits VLR resources in the RAC procedure outside of the SCUC economic process based on VLR load trigger levels. The VLR units so committed (outside the economic commitment process) likely will not set the LMPs. Moreover, the minimum capacity blocks of these committed VLR units not only reduce power flows on the system, including those on any (N-1) congested flowgates, but also effectively displace resources lower in the merit order that would otherwise have been dispatched, often resulting in slightly lowered LMPs. As a result, the level of congestion observed in the system in the base case in which the VLR commitments are reflected using the load trigger levels (as done in actual MISO operations) generally is far less than a scenario where N-1, G-1 flowgates are used to model the VLR commitments.

In the change case, where the load trigger levels are relaxed with the inclusion of the transmission upgrade, the minimum capacity blocks of the VLR units are no longer present in the system, resulting in dispatch on the basis of the merit order, a more reasonable estimate of the economic benefit (vis-a-vis the benefit observed when N-1, G-1 flowgates are used to commit VLR resources), and often a small increase in the system LMPs. Entergy thus has urged MISO to model the estimated WOTAB VLR load trigger level changes resulting from the WOTAB economic project in PROMOD to ensure that the level of benefits resulting from the project that has been predicted using the N-1, G-1 flowgates is reasonable and consistent with what would be expected in actual operations.

Moreover, the inclusion of N-1, G-1 flowgates to simulate VLR commitments further distorts MISO’s model results by introducing two additional differences between the manner in which the MISO energy market is simulated in the MTEP PROMOD models and the manner in which the MISO DA and RT energy markets actually operate. First, the N-1, G-1 flowgates are enforced for both commitment and dispatch in the PROMOD model. On the other hand, the VLR commitment rules actually used in operations, which are based on N-1, G-1 contingencies, are generally commitment-only guides and therefore are used only to commit VLR resources. The dispatch of such resources (beyond their minimum capacity) in the DA and RT markets takes place through the security constrained economic dispatch process which employs N-1 flowgates only. This discrepancy has the effect of over-estimation of the dispatch of VLR resources in the PROMOD model (versus the dispatch production that could be expected to occur in actual operations in the DA and RT market), and therefore results in the over-estimation of the benefits associated with an economic project that is designed to produce VLR benefits. Second, a large percentage of the emergency energy observed in the MTEP17 PROMOD models is a result of congestion associated with these N-1, G-1 flowgates, which are not enforced in the security constrained unit commitment and dispatch process in the DA and RT markets, as mentioned above. Because an excessively large portion of the economic benefit resulting from the WOTAB economic project is a consequence of the reduction in the emergency energy production in the PROMOD base cases, MISO’s VLR modeling methodology and the excessive production of emergency energy are linked and together contribute to the unreasonable overestimation of the economic benefits resulting from the WOTAB economic project.

Table 5.3-9; the last column quantifying the emergency energy contribution to project benefits:

Entergy’s concerns about the current MISO economic planning process with regards to emergency energy have been discussed at numerous EPUG meetings and through written comments submitted by Entergy throughout this year. Entergy stands by its prior comments on emergency energy and while Entergy does not now fully rehash its prior arguments on emergency energy, the Operating Companies provide the following feedback:

MISO has failed to address the concern that Entergy has raised repeatedly -- the acceptable threshold amount of emergency energy production (in MWh) in the MTEP base cases. In addition, MISO has not addressed, in either its written response in the EPUG meeting materials or in the whitepaper, the modeling and process changes that are required to reduce the amount of emergency energy in the model to reasonable amounts in MTEP cycles going forward, nor has MISO put forth any strawman proposal of what levels of emergency energy are reasonable.

Xcel Energy

Xcel Energy appreciates MISOs continued efforts for improvement and increased levels of opportunities for stakeholder feedback during the MTEP17 planning cycle. Throughout the MTEP17 economic planning process Xcel Energy has provided input on the development and process for the identification and solution of economic inefficiencies on the MISO system. As the development progressed to the eventual recommendation of the WOTAB 500kV candidate Market Efficiency Project, Xcel Energy remained involved and supported the process in which that project was developed. While we remain supportive of the process and recognize that the defined process for identification of a Market Efficiency Project has been followed and believe this process produced an economically beneficial project, we have concerns about specific instances of misalignment of the MTEP17 process and the process defined in the MISO Tariff and Business Practice Manuals, inconsistencies with the defined project scope as well as concerns about current uncertainties in the regulatory environment and limited access to the project area.

The first concern is an issue that Xcel Energy has raised several times. This concern is the changing of the Futures weighting after the approval of the designated weights developed through and open and inclusive stakeholder process. This change also was allowed after the release of the top congested flowgate analysis and after the closure of the open project submittal window. We are concerned that by allowing this change in the designated weights, MISO has set a very dangerous precedent and gave the perception of favoritism by MISO among the MISO stakeholders. We do recognize that this change in weights did not create a significant enough difference in the study results to skew any project recommendations, but remain concerned of the lasting impacts of allowing this change.

Secondly, Xcel Energy has performed an in depth review of the MISO detailed cost estimate, following MISO's recommendation of selecting Alternative 2, from which the baseline project cost is set and the benefit to cost ratio is calculated. During this review, we have found several areas where the MISO detailed cost estimate does not align with the defined process detailed in the minimum design requirements for competitive projects and the MISO defined cost estimation process as well as a misalignment between the defined project scope and the project's cost estimate. These concerns are detailed below:

1. MISO's Project Cost Estimation Data document for Transmission and Substation Project Cost Estimation Data states in Section 3.1 Scoping-Level Transmission Line Estimate Overview:

    > *"Scoping-Level Estimates are based on a more detailed scope definition when compared to Planning-Level Estimates. MISO uses Google Earth program for potential route identification for the proposed transmission line project following existing overhead line corridors between two substations."*

    During the MTEP17 Market Congestion Planning Study (South) Project Recommendations presentation at the September 27, 2017 Planning Advisory Committee Meeting, MISO confirmed that the $129.7M cost estimate was a Scoping-Level Estimate.

Using the route identification criteria noted above for Scoping-Level Estimates of following existing overhead line corridors, the closest re-creation of the 500kV transmission line route is approximately 24 miles (plus the 1 mile 230kV lines). This length does not include any contingency for unknowns for routing constraints, unground pipelines, homes and business and an approved route from applicable regulatory jurisdiction(s).

2. The eastern side of Texas and western Louisiana is a web of underground pipelines, see attached image showing major pipelines in the area of the project. The vast amount of pipelines will significantly impact the routing of the transmission line as well as pipeline mitigation to prevent increased corroding of the pipelines. There does not appear to be any defined costs in the MISO cost estimate to address pipeline mitigation which typically costs $500,000/mile ($300,000 to over $1million per mile depending on distance pipeline size and voltage).

3. The Segment 2: 230kV Transmission Line portion of the MISO WOTAB economic project Alternative 2 cost estimate does not appear to cover re-termination for both double circuit transmission lines but rather a single double circuit route and does not align with the Transmission and Substation Project Cost Estimation Data and defined project scope:
    a. The Right-of-Way widths identified in the Transmission and Substation Project Cost Estimation Data states in Section 3.2 that Right-of-Way widths for a 230kV double circuit are 150 feet and 125 feet for a 230kV single circuit. The Hartburg-New Substation Transmission Line Estimate states that the 230kV transmission line is a single double circuit but only uses 125 foot Right-of-Way which contradicts the Transmission and Substation Project Cost Estimation Data.
    b. The land cost only identifies 1 mile (plus 5% adder), where two miles would be needed to cover the 2 – 230kV double circuit lines (one double circuit going into the New Substation and one double circuit coming out of the New Substation).
    c. The Segment 2: 230kV Transmission Line cost estimate indicates there are 4 structures (1 tangent and 3 deadends) for the transmission line. The Transmission and Substation Project Cost Estimation Data states in Section 3.2 that the average span length for a 230kV double circuit is 600 feet. Each mile of 230 kV double circuit would require 8 structures, but the project needs 2 – 230kV double circuit transmission lines for a total of 16 structures.
    d. The defined project scope for Alternative #2 is defined as re-terminating both of the existing 230kV circuits into the New Substation. As stated above the estimate only defines a single route for a double circuit connection to the new substation, which is approximately half of the distance of what would be required by the defined project scope for the 230kV re-termination.

4. The Competitive Transmission Monthly Update presentation at the September 27, 2017 Planning Advisory Committee Meeting, provided a slide to show what facilities would be eligible for the Developer Selection Process for the WOTAB project. However, the slide does not show who is responsible for cutting or tapping into the existing Sabine to McFadden and Sabine to Nederland 230kV double circuit transmission lines. The MISO WOTAB economic project Alternative 2 cost estimate also does not include any costs for Entergy (or another party) to cut into the existing Sabine to McFadden and Sabine to Nederland 230kV double circuit transmission lines, install dead-end structures at each cut location (2) and other associated work. We assume that the Selected Developer would install the Entergy provided jumpers onto its first structure closest to the new Entergy deadened structures.

5. While not restricted in the BPM-029 language, this detailed estimate only contains enough substation equipment to construct a ring bus configuration. This does meet the minimum design standards, but

may represent a significantly lower cost if a breaker-and-a-half configuration would be required for reliability or expansion capability reasons.

6. Due diligence access to the project area maybe limited. As the rebuilding process after Hurricane Harvey passed through this area is currently underway, there is uncertainty as to whether the appropriate due diligence can be performed to enable an adequately robust competitive solicitation process.

7. There is currently an open request for a declaratory order on the existence of a state Right of First Refusal (ROFR) within Texas. As the issuance of this declaratory order continues to be been postponed by the Texas commission, there is a question as to whether a competitive process should be performed with the possibility of direct assignment due to state processes if a ROFR is confirmed.