BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION OF XCEL ENERGY AND ITC MIDWEST LLC, FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345-KV TRANSMISSION LINE PROJECT

MPUC Docket No. E6675,E002/CN-17-184
OAH Docket No. 82-2500-35157

REBUTTAL TESTIMONY AND ATTACHMENTS OF MATTHEW LANDI

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DECEMBER 18, 2018

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TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. Please state your name.

A. My name is Matthew Landi.

Q. Are you the same Matthew Landi who previously submitted Direct Testimony on behalf of the Minnesota Department of Commerce, Energy Regulation and Planning unit (DOC-DER) in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I respond to the Direct Testimony of Xcel Energy and ITC Midwest LCC (Applicants) witnesses Andrew W. Siebenaler and Benjamin T. Abing regarding:

- Applicants' updated alternatives analysis described in Mr. Siebenaler's Direct Testimony;
- Applicants' updated internal cost analysis of the proposed 345 kV Huntley-Wilmarth Transmission Line (proposed Project) using 2018 Transmission Expansion Plan (MTEP18) modeling assumptions also described in Mr. Siebenaler's Direct Testimony; and
- Applicants' updated external cost analysis of the proposed Project described in Mr. Abing's Direct Testimony.

Q. Do you change your position in this testimony?

A. No. As indicated in the "Conclusion" section below, I maintain my prior recommendations; however, my goal is to assist in ensuring that the record before the Commission and Administrative Law Judge is reasonably complete and accurate.

II. REBUTTAL TO APPLICANTS' DIRECT TESTIMONY

A. RESPONSE TO MR. SIEBENALER'S DIRECT TESTIMONY

1. Updated Analyses of 161 kV Alternative Using the Midcontinent Independent System Operator's 2018 Transmission Expansion Plan (MTEP18)

Q. What did Mr. Siebenaler's Direct Testimony indicate regarding the proposed Project compared to potential alternatives?

A. Mr. Siebenaler's Direct Testimony indicated that the Applicants performed additional analyses related to alternatives to the proposed Project, based on Midcontinent Independent System Operator's (MISO) 2018 updates to the MISO transmission expansion plan of the (MTEP18). The Applicants' additional analyses of alternatives to the proposed Project resulted in the same conclusion: the proposed Project remains the best solution to address the identified congestion issue.[1]

Q. How do the MTEP18 Futures compare to the MTEP17 Futures?

A. MTEP17 had three Futures: Existing Fleet, Policy Regulations and Accelerated Alternative Technologies, as described in the Petition (Ex. XC-__ at 87-89,

[1] Ex. XC-__ at 42 (Siebenaler Direct).

Petition) and my Direct Testimony (Ex. DOC-DER-___ at 20-21 (Landi Direct)). As explained by Mr. Siebenaler, and in review of the Final Draft of the MTEP18 Report, the MTEP18 modeling assumptions included four Futures scenarios:[2] (1) Limited Fleet Change (LFC); (2) Continued Fleet Change (CFC); (3) Accelerated Fleet Change (AFC); and (4) Distributed & Emerging Technologies (DET).

Q. Please describe the additional analyses of alternatives to the proposed Project that the Applicants' performed in light of MTEP18.

A. Mr. Siebenaler's Direct Testimony stated on page 39 that the Applicants performed additional internal cost analyses of a new Huntley-Wilmarth 161 kV transmission line (161 kV alternative) using MTEP18 modeling assumptions. Table 8 of Mr. Siebenaler's Direct Testimony provided a comparison of the costs, weighted benefit-to-cost (BC) ratios, and the 20-year weighted present-value (PV) benefit of the proposed Project and the 161 kV alternative under MTEP17 and MTEP18 modeling assumptions. Together, the weighted PV benefit and the weighted BC ratio represent a measure of the expected economic benefits of the proposed Project and the 161 kV alternative.

Q. What effect did use of MTEP18 modeling have on the estimated benefits of the 161 kV alternative?

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[2] *Id.* at 23-25, 28; Ex. DER-__, ML-R-1 (Landi Rebuttal) (MTEP18 Report Book 1: Transmission Studies Final Draft, at 77-82)

A. Table 8 indicates that the 161 kV alternative is less economically beneficial when analyzed under MTEP18 as opposed to MTEP17 modeling assumptions. Specifically, its weighted BC ratio reduced from 2.05 under MTEP17 to 1.24 under MTEP18, and its 20-year PV benefit reduced from $200.7 million under MTEP17 to $119.43 million under MTEP18.

Q. What effect did use of MTEP18 modeling have on the estimated benefits of the proposed Project?

A. Likewise, use of the MTEP18 modeling assumptions reduced the estimated benefits of the proposed Project. Table 8 of Mr. Siebenaler's Direct Testimony indicates that, based on the Applicants' original project cost estimate of $121.3 million, the weighted BC ratio of the proposed Project reduced from 1.88 under MTEP17 to 1.47 under MTEP18, and its 20-year PV benefit reduced from $275.83 million under MTEP17 to $212.61 million under MTEP18.[3] (I discuss in the next section of my testimony the appropriateness of basing these analyses on the Applicants' original project cost estimates.)

Q. Were you able to confirm Mr. Siebenaler's analysis?

A. Yes. I confirmed that Mr. Siebenaler's updated internal cost analysis was performed using the same methodology as the Applicants' original internal cost analysis. Using

[3] Table 6 of Mr. Siebenaler's Direct Testimony provides a more detailed overview of the internal cost analysis of the proposed Project using MTEP18 modeling assumptions, with a range of PV of benefits and BC ratios encompassing these values. Specifically, based on the Applicants' original project cost estimates ranging from $105.8 million to $138.0 million, the PV benefit of the proposed Project using MTEP18 modeling assumptions is $217.97 million (in 2016$), and the weighted BC ratios range from 1.30 to 1.69.

MTEP18 modeling assumptions, the Applicants determined the Adjusted Production Cost (APC) savings of the proposed Project, which serve as the basis of the economic benefits of the proposed Project (as explained on page 21 of my Direct Testimony and on page 62 of the Applicants' Petition). Once the APC savings were determined, standard economic analysis techniques were applied to determine the 20-year PV benefit and the weighted BC ratio of the proposed Project.

Q. What does this information tell you about the effects of using MTEP18 rather than MTEP17 modeling assumptions on the expected economic benefits of the proposed Project compared to the 161 kV alternative?

A. I conclude that, while the expected benefits of both the proposed Project and the 161 kV alternative decreased using the MTEP18 rather than MTEP17 assumptions, the proposed Project is still superior to the 161 kV alternative overall. Moreover, according to the Applicants' analysis in Table 8 of Mr. Siebenaler's Direct Testimony, only the proposed Project exceeds a weighted BC ratio of 1.25, which is the minimum BC ratio to qualify for a Market Efficiency Project under MISO's tariff.

Q. What other analysis did the Applicants provide in Mr. Siebenaler's Direct Testimony?

A. In addition to the internal cost analysis, Mr. Siebenaler updated the analysis of the abilities of the proposed Project and the 161 kV alternative in relieving the identified congestion issue under MTEP18 as opposed to MTEP17 modeling assumptions.

Q. Did use of MTEP18 modeling have any effect on the results of the relative abilities of the proposed Project and the 161 kV alternative to relieve expected congestion?

A. No. Using the MTEP18 modeling assumptions, Mr. Siebenaler's analysis continued to indicate that the 161 kV alternative would underperform compared to the proposed Project as the 161 kV alternative would not fully alleviate the identified congestion issue over the 10-year study period. Specifically, his analysis indicated that, while the 161 kV alternative would initially reduce 99% of the identified congestion issue in 2022, it would only relieve 94% and then 85% of the identified congestion issue by 2027 and 2032.[4]

By contrast, the proposed Project would alleviate 100% of the identified congestion issue throughout the entire 10-year study period, even using the MTEP18 modeling assumptions.

Q. Did Mr. Siebenaler provide any other updated analysis using the MTEP18 modeling assumptions?

A. Yes. He compared the impacts of proposed Project and the 161 kV alternatives on reducing wind generation curtailments using MTEP18 modeling assumptions. His analysis indicated that the proposed Project would outperform the 161 kV alternative in its ability to reduce curtailments in each of the four MTEP18 Futures.

The results of Mr. Siebenal's analysis using MTEP18 modeling assumptions indicated that the proposed Project would reduce curtailments by between 2.6% and

[4] Ex. XC-__ at 40 (Siebenaler Direct).

18.4%, whereas the 161 kV alternative would reduce curtailments by a lesser amount, between 1.4% and 12.1%.[5]

Q. Overall, what are your conclusions regarding Mr. Siebenaler's updated analysis of the proposed Project and the 161 kV alternative, using MTEP18 modeling assumptions?

A. I conclude that the proposed Project remains the best option to address the identified congestion issue for the following reasons:

- The proposed Project would relieve 100% of the identified congestion issue throughout the 10-year study period, whereas the 161 kV alternative would not;
- The proposed Project would be more economically beneficial due to its higher 20-year PV benefit and weighted BC ratio compared to the 161 kV alternative; and
- The proposed Project would reduce wind generation curtailments to a greater extent than the 161 kV alternative under each of the MTEP18 Futures.

2. Updated Analysis of Proposed Project Including Routing Costs

Q. Should the internal cost analysis be based exclusively on the Applicants' original project cost estimates?

[5] *Id.*

A. No. As explained on page 23 of my Direct Testimony, the original project cost estimates do not reflect all of the routing options considered in the Minnesota Department of Commerce, Energy Environmental Review & Analysis' (DOC-EERA) EIS Scoping Decision (Scoping Decision Routes). The DOC-EERA's EIS Scoping Decision materially affects the range of project cost estimates, resulting in estimates ranging from $104.8 million to $160.7 million (in 2016$).

Q. Did the Applicants perform updated internal cost analysis of the proposed Project that reflect the range of project cost estimates of the Scoping Decision Routes?

A. Yes. As described on page 35 of Mr. Siebenaler's Direct Testimony, Table 7 summarizes the Applicants' internal cost analysis of the proposed Project using MTEP18 modeling assumptions and the project cost estimates of the Scoping Decision Routes. As described in Table 7, using those assumptions, the weighted PV benefit of the proposed Project is $217.97 million (in 2016$) and the weighted BC ratios range from 1.11 to 1.71.

Q. How does this result compare to the internal cost analysis performed by the Applicants as presented in the Petition and in response to DOC-DER's information requests?

A. The expected benefits are lower, once MTEP18 and routing costs are included. The original internal cost analysis of the proposed Project performed by the Applicants on page 92 of the Petition, which was based on MTEP17 modeling assumptions and the original project cost estimates ranging from $105.8 million to $138.0 million, indicated a weighted PV benefit $273.11 million (in 2016$) and weighted BC ratios ranging from 1.64 to 2.18. In the supplemental response to DOC DER IR No. 23, the Applicants provided updated internal cost analysis using project cost estimates of the Scoping Decision Routes: the weighted PV benefit increased slightly to $275.83 million and the weighted BC ratios ranged from 1.42 to 2.18.[6]

The updated internal cost analysis and use of MTEP18 information indicated a downward revision in the estimate of the economic benefits of the proposed Project.

Q. Can you provide general guidance on which estimates of the economic benefit of the proposed Project are more accurate?

A. Yes. Generally, the Applicants' estimates of the economic benefit of the proposed Project have varied throughout the proceeding. There are two primary factors that explain why their estimates changed: (1) differences in the project cost estimates; and (2) differences in the modeling assumptions.

To develop a reasonably complete and accurate record, internal cost analyses that include estimated costs of the Scoping Decision Routes reflect a more accurate estimate of the potential economic benefit of the proposed Project. The original project cost estimates are based on specific routes that are no longer being considered or have been modified, and are therefore outdated. The internal cost analyses that use the project cost estimates of the Scoping Decision Routes are more accurate.

[6] Ex. DER-___ , ML-9 (Landi Direct).

B. RESPONSE TO MR. ABING'S DIRECT TESTIMONY – UPDATED EXTERNALITIES ANALYSIS

Q. What aspects of Mr. Abing's Direct Testimony do you address?

A. I respond to Mr. Abing's updated externalities analysis using the proposed Project costs associated with the Scoping Decision Routes.

Q. What did your Direct Testimony indicate regarding an externalities analysis?

A. I provided on page 38 of my Direct Testimony an externalities analysis using updated project cost estimates from the Scoping Decision Routes and the Applicants' Public Policy Benefits estimates. More specifically, I provided updated externalities analysis using new estimates of low, medium, and high project cost estimates based on the Scoping Decision Routes. Further, on pages 39-40 of my Direct Testimony, I compared the Applicants' externalities analysis to my own.

Table 8 on page 40 of my Direct Testimony indicated that, under my analysis, there would be higher net benefits for the low-cost route than under the Applicants' analysis, whereas there would be lower net benefits for the medium and high cost route options under my analysis compared to the Applicants' analysis.

Q. What did Mr. Abing's updated externalities analysis indicate?

A. Mr. Abing's updated externalities analysis incorporated the highest cost route of the Scoping Decision Routes (the Purple-E-Red Route, with an estimated cost of $160.7 million) in the calculation of the proposed Project's net benefits.[7] As explained on pages

[7] Ex. XC-__ at 8 (Abing Direct)

34-36 of my Direct Testimony, the net benefits of the proposed Project include: (1) a modified version of the economic benefits derived from the Applicants' internal cost analysis; (2) the "Public Policy Benefits" of the proposed Project derived from the impact that the proposed Project is expected to have on air quality; and (3) the annual revenue requirements of the proposed Project. Figure 1 of my Direct Testimony on page 35 provides a simple formula to help illustrate the Applicants' calculation of net benefits.

Mr. Abing's updated estimates of the net benefits of the highest cost route indicated a reduction in net benefits compared to the Petition's original analysis: net benefits reduced from approximately a range of $367.8 million to $722.9 million as originally estimated to approximately $334.3 million to $689.4 million (in 2016$).[8]

Q. How does Mr. Abing's updated external cost analysis compare to the external cost analysis described in your Direct Testimony?

A. Mr. Abing's Direct Testimony updated the Applicants' externalities analysis by providing an analysis of the net benefits of the highest cost route of the Scoping Decision Routes. He did not provide an updated analysis of low and medium project cost estimates using the Scoping Decision Routes, as I did in my Direct Testimony. However, his updated externalities analysis of the highest cost route of the Scoping Decision Routes matches my own analysis: I also concluded that the Purple-E-Red Route has net benefits ranging from approximately $334.3 million to $689.4 million (in 2016$).

[8] *Id.*

Q. Given the similarity between the net benefits of the Purple-E-Red Route calculated by Mr. Abing and your own analysis, what do you conclude regarding the externalities analysis overall?

A. I conclude that the Department's and the Applicants' externalities analysis reach the same conclusions regarding the results of the high cost route. Since Mr. Abing's updated externalities analysis matched my own for the net benefits of the Purple-E-Red Route, it appears that our methodology is the same. I would expect that if Mr. Abing used the same project cost estimates for the low and medium project cost route options as provided in the Scoping Decision Routes, the resulting net benefits calculation would be similar to my own analysis.

Q. Does the Applicants' updated externalities analysis change the conclusion that the proposed Project is superior to the 161 kV alternative due to the higher net benefits associated with the proposed Project?

A. No. The Applicants' updated externalities analysis continues to support the conclusion that the proposed Project has higher net benefits than the 161 kV alternative. As explained in Table 7 on page 38 of my Direct Testimony, the highest project cost estimate of the proposed Project has net benefits ranging from \$334.3 million to \$689.4 million (in 2016\$), whereas the 161 kV alternative has net benefits ranging from \$295.5 million to \$551.8 million (in 2016\$). Therefore, in terms of net benefits, I conclude that the proposed Project is a better option than the 161 kV alternative.

III. CONCLUSION

Q. Overall, what do you conclude, based on the analysis above?

A. I conclude that the Applicants' updated internal cost analysis using MTEP18 modeling assumptions demonstrated that the proposed Project remains a better option compared to the alternatives considered by the Applicants. Further, I conclude that the Applicants' updated externalities analysis reinforces the conclusion that the proposed Project is a better option compared to the 161 kV alternative due to the proposed Project's higher net benefits.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

MTEP18 FINAL DRAFT

MISO TRANSMISSION EXPANSION PLAN

MTEP18 REPORT

Book 1

Transmission Studies

Table of Contents

Section 2: MTEP Overview

2.1 Investment Summary

The 442 new Appendix A projects in MISO's 2018 Transmission Expansion Plan (MTEP18) represent \$3.3 billion[1] in transmission infrastructure investment and fall into the following categories:

- **81 Baseline Reliability Projects (BRP) totaling \$709 million**— BRPs are required to meet standards for both North American Electric Reliability Corporation (NERC) and regional reliability
- **16 Generator Interconnection Projects (GIPs) totaling \$255 million** — GIPs are required to reliably connect new generation to the transmission grid
- **341 Other Projects totaling \$2.3 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. Three Other projects, totaling \$29 million, were identified through the Market Congestion Planning Study.
- **2 Transmission Deliverability Service Projects (TDSP) totaling \$285,000** — TDSPs are network upgrades driven by Transmission Service Requests (TSR)
- **2 Targeted Market Efficiency Projects (TMEP) totaling \$4 million** — TMEPs are interregional projects, with Pennsylvania-based PJM, that address historical Market-to-Market congestion along the MISO-PJM seam

The 10 largest projects represent 23 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

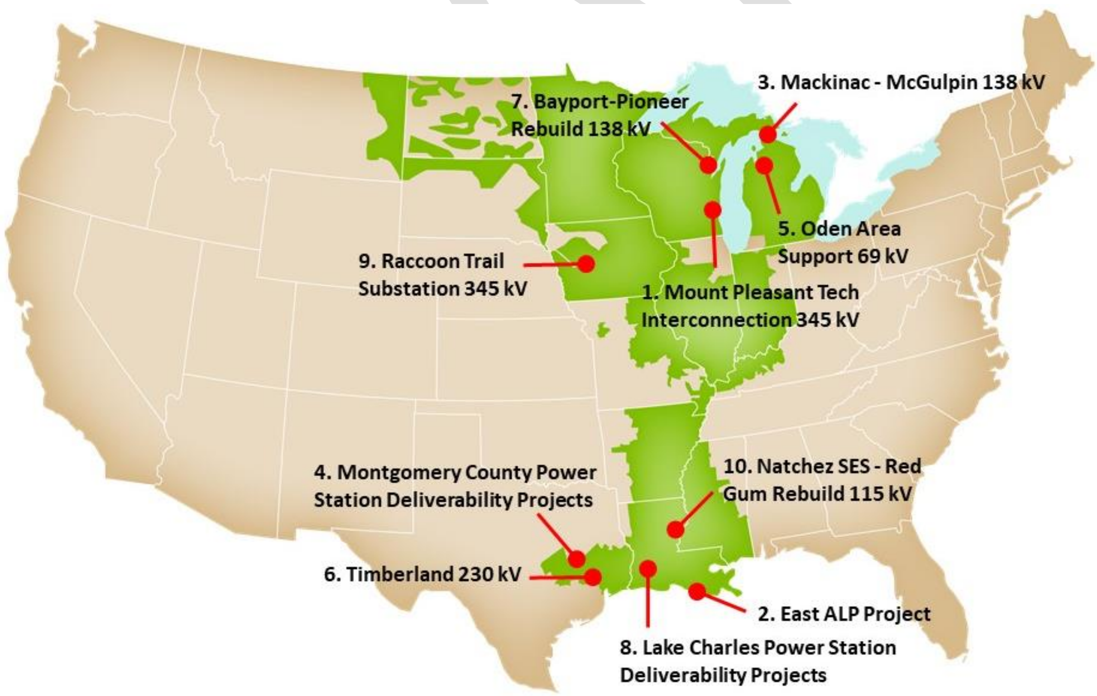


Figure 2.1-1: Top 10 MTEP18 new Appendix A projects (in descending order of cost)

[1] The MTEP18 report and project totals reflect all project approvals during the MTEP18 cycle, including those approved on expedited project review basis prior to December 2018.

The new projects recommended for approval in MTEP18 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP18 Appendix A contain four cost-shared Generator Interconnection Projects. Cost sharing information is provided in Section 2.2: Cost Sharing Summary.

MISO Region	GIP	Other	TDSP	TMEP	BRP	Total
Central	$11,936,823	$468,850,975		$4,475,000	$39,050,415	$524,313,213
East	$8,376,000	$348,151,409			$206,432,000	$562,959,409
South	$149,651,049	$303,143,174	$285,025		$333,140,582	$786,219,830
West	$84,931,359	$1,196,817,962			$130,356,259	$1,412,105,580
Grand Total	$254,895,231	$2,316,963,520	$285,025	$4,475,000	$708,979,256	$3,285,598,032

Table 2.1-1: MTEP18 New Appendix A investment by project category and planning region

Other Project Type

The majority of Other projects address localized reliability issues — either due to aging transmission infrastructure, or local non-baseline reliability needs that are not dictated by NERC and regional reliability standards (Figure 2.1-2). The remaining projects mostly address distribution concerns, with a small percentage of projects targeting localized economic benefits or line relocations to accommodate other infrastructure.

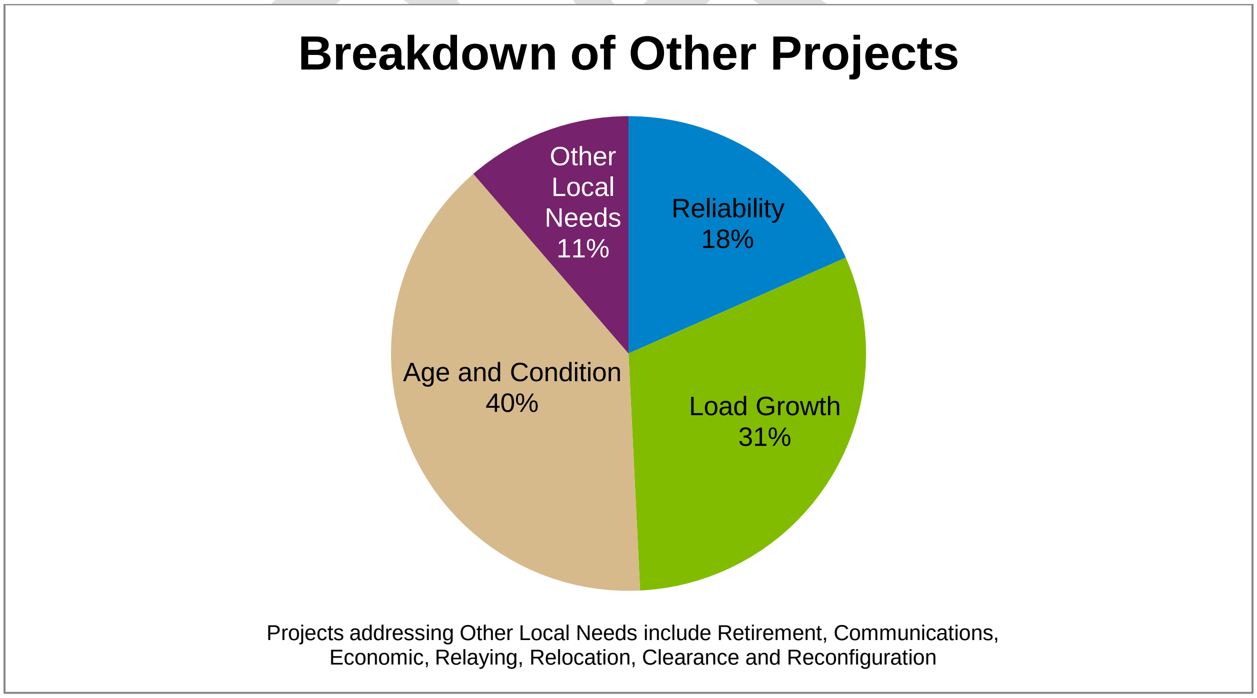


Figure 2.1-2: Breakdown of new MTEP18 Appendix A Other projects

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 a facility estimated cost of 50 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. Thirty-five percent of MTEP facility costs go toward line upgrades, which include rebuilds, conversions and relocations. Only about 15 percent of facility costs are dedicated to new lines on new right-of-way across the MISO footprint.

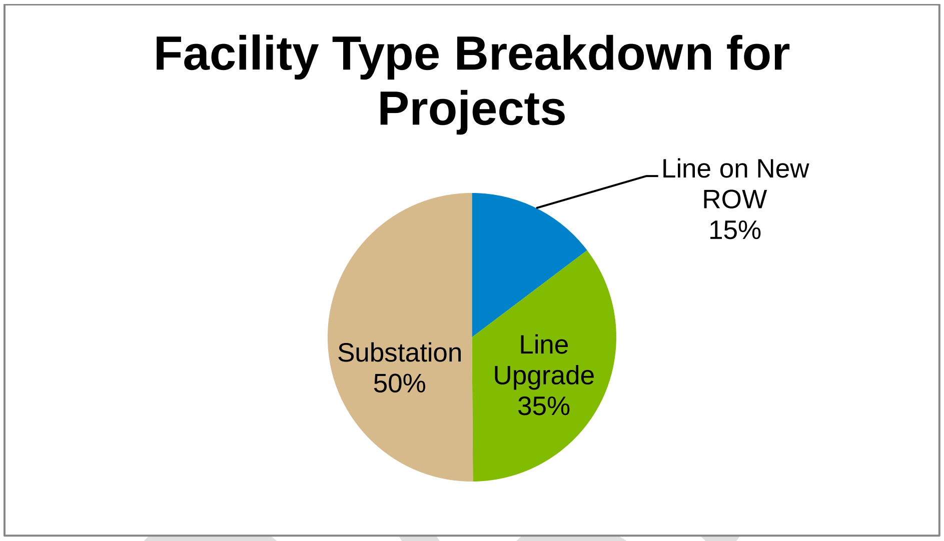


Figure 2.1-3: Facility type for new MTEP18 Appendix A projects

New Appendix A projects are spread over 14 states, with 10 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 transmission capacity in other parts of the system is consumed and new build becomes necessary.

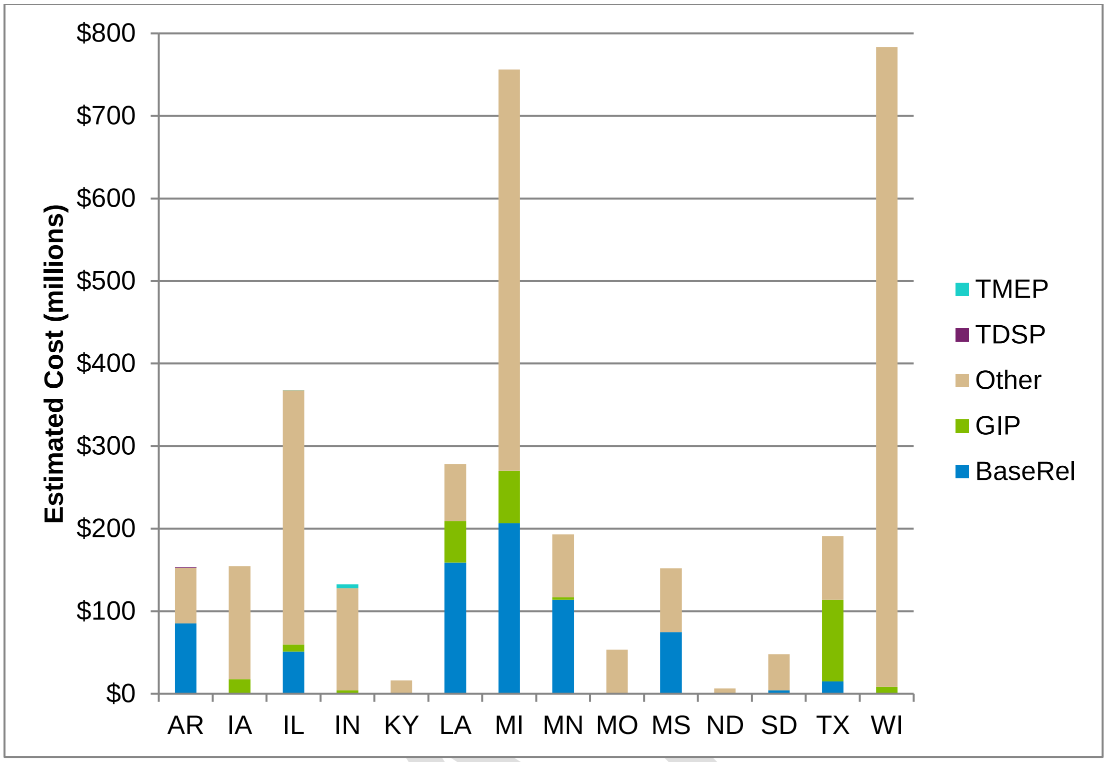


Figure 2.1-4: New MTEP18 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP18 new projects, increases to 1,081 projects amounting to approximately $13 billion of investment through the next 10 years (Figure 2.1-5). The list of Active Appendix A projects 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.

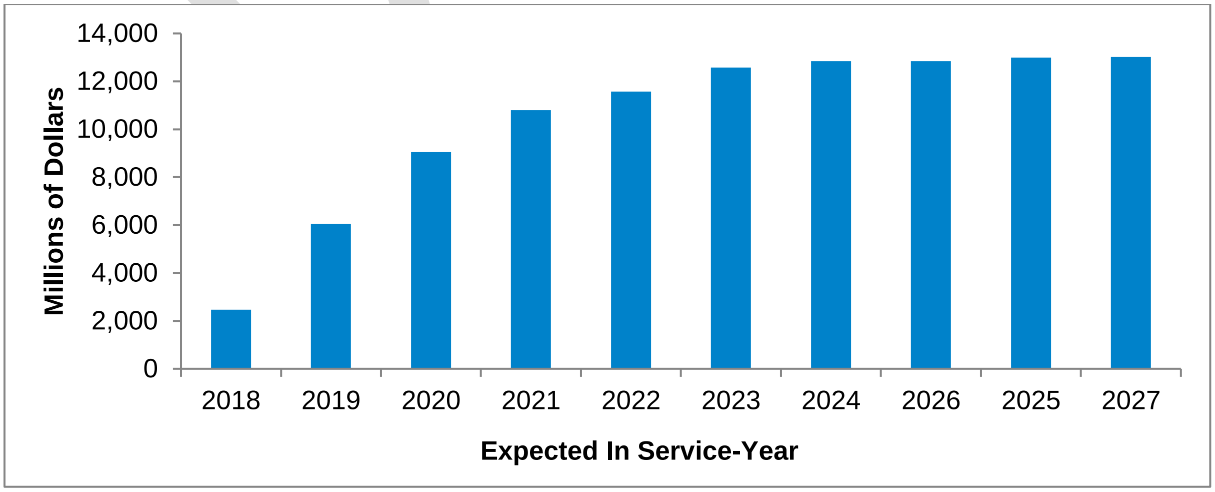


Figure 2.1-5: MTEP18 Appendix A projected cumulative investment by year

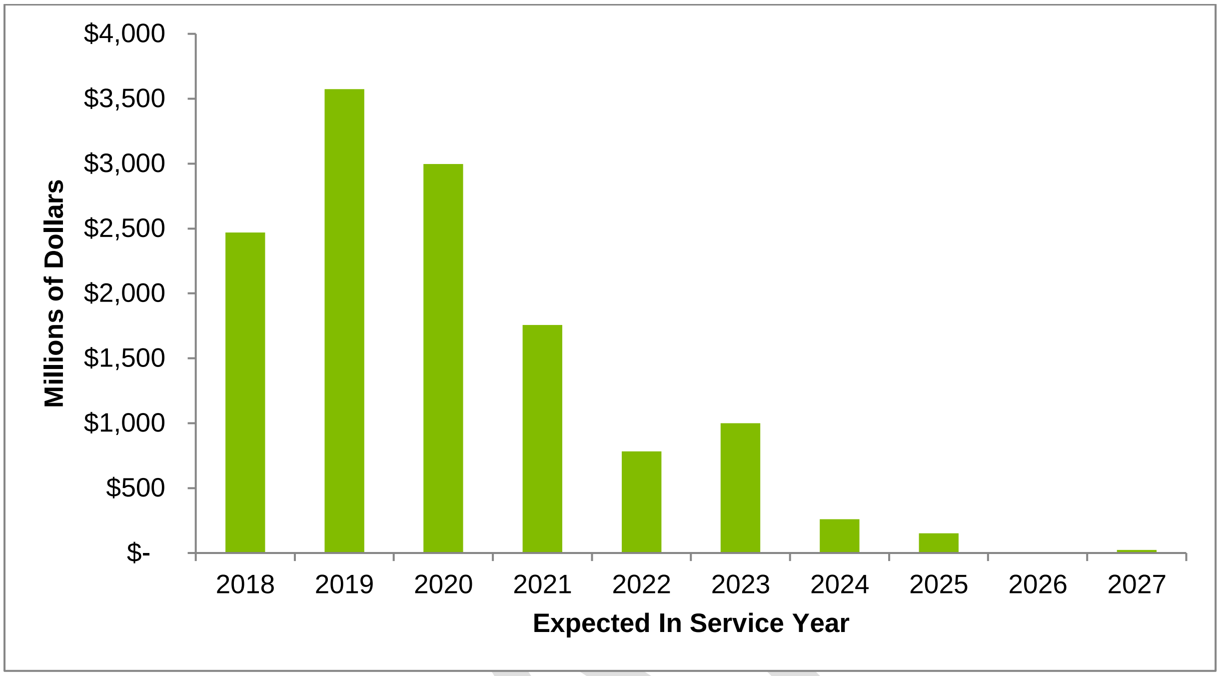


Figure 2.1-6: MTEP18 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[2] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $14.4 billion with another $3.4 billion in Appendix B. New MTEP18 Appendix A projects represent approximately $3 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $3.8 billion of the $14.4 billion cumulative in Appendix A is from the active 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).

[2] https://cdn.misoenergy.org/Current%20Members%20by%20Sector95902.pdf

MISO Region	Number of Appendix A Projects	Appendix A Estimated Costs	Number of Appendix B Projects	Appendix B Estimated Costs
Central	214	$2,289,577,702	61	$159,479,940
East	240	$1,879,742,495	39	$547,218,000
South	206	$3,699,198,701	86	$1,712,533,292
West	421	$6,615,834,004	63	$957,622,980
Grand Total	1081	$14,484,352,902	249	$3,376,854,212

Table 2.1-2: Projected transmission investment by planning region

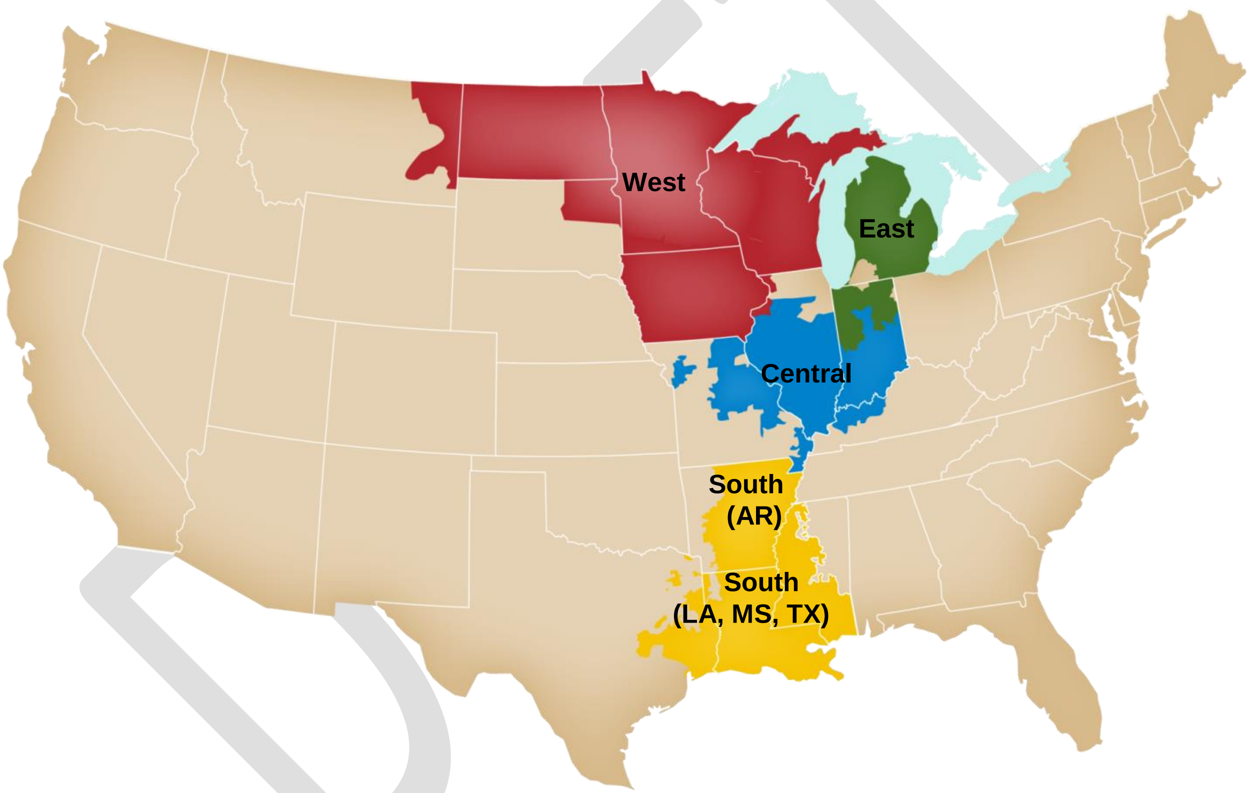


Figure 2.1-7: MISO footprint and planning regions

Active Appendix A Line Miles Summary

MISO has approximately 68,500 circuit-miles of existing transmission lines. There are approximately 5,900 circuit-miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in MTEP18 Appendix A (Figure 2.1-8, Table 2.1-3).

- 4,000 circuit-miles of upgraded transmission line on existing corridors are planned
- 1,900 circuit-miles of new transmission line on new corridors are planned

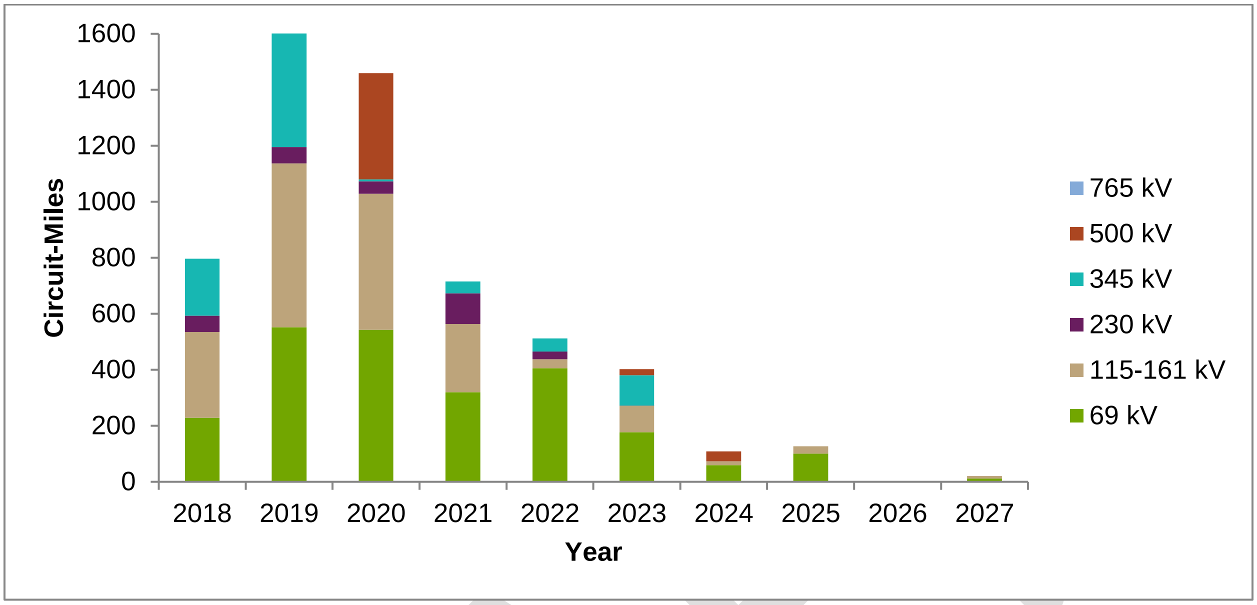


Figure 2.1-8: Planned new or upgraded line circuit-miles by voltage class (kV) in Appendix A through 2028

Year	<100 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2018	303	305	58	204			870
2019	632	585	59	406			1682
2020	576	486	45	7	380		1493
2021	341	243	110	42			736
2022	408	32	27	47			514
2023	177	94	1	108	22		402
2024	60	14			35		108
2025	100	27					127
2026							
2027	12	9					21
Grand Total	2609	1796	300	813	437		5955

Table 2.1-3: Planned new or upgraded line circuit-miles by voltage class (kV) in Appendix A through 2028

2.2 Cost Sharing Summary

New MTEP18 Appendix A Cost-Shared Projects

MTEP18 recommends a total of 11 new cost-shared eligible projects for Appendix A with an estimated cost of $91.4 million. The 11 eligible projects include:

- Nine Generator Interconnection Projects (GIP) with a total estimated project cost of $86.9million, where $37.4 million is allocated to load, and the remaining $49.5 million is allocated directly to generators.[3]
- Two Targeted Market Efficiency Projects (TMEP) with a total cost of $4.5 million, where the MISO cost responsibility is $4.2 million, and the remaining $300,000 is allocated to PJM.

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment. For GIPs, 10 percent of the cost of associated 345 kV network upgrades is allocated to load on a region-wide basis based on load ratio share. In some special situations, costs of GIP network upgrades greater than 100 kV may be distributed to benefiting pricing zones on the basis of line outage distribution factor calculations. For Market Efficiency Projects, a portion of costs are distributed to Cost Allocation Zones based on the adjusted production cost benefits; 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.

Cost Allocation between Planning Areas for GIPs and MEPs

The integration of the MISO South region on December 19, 2013, started a cost allocation transition period 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, currently scheduled for the end of MTEP18.[4] The cost-shared projects in MTEP18 all terminate exclusively in one planning area, and are cost shared amongst their respective pricing zones (Table 2.2-1).

[3] Note that the costs indicated as "allocated to generators" does not account for the Transmission Owners who reimburse qualifying generators 100 percent of the costs incurred for Generation Interconnection Projects.
[4] 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 years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period.

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 207 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[5] (BRP) and GIPs, and was later augmented with MEPs in 2007 and Multi-Value Projects (MVP) in 2010. Cost sharing further expanded in 2017 with the addition of TMEPs with PJM. 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 $10.7 billion in transmission investment, including the 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) — 71 projects, $3.2 billion
- Generation Interconnection Projects (GIP) — 106 projects, $745.7 million (including the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — 5 projects, $317.4 million
- Multi-Value Projects (MVP) — 17 projects, $6.5 billion
- Targeted Market Efficiency Projects (TMEP) – 7 projects, $10.8 million

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

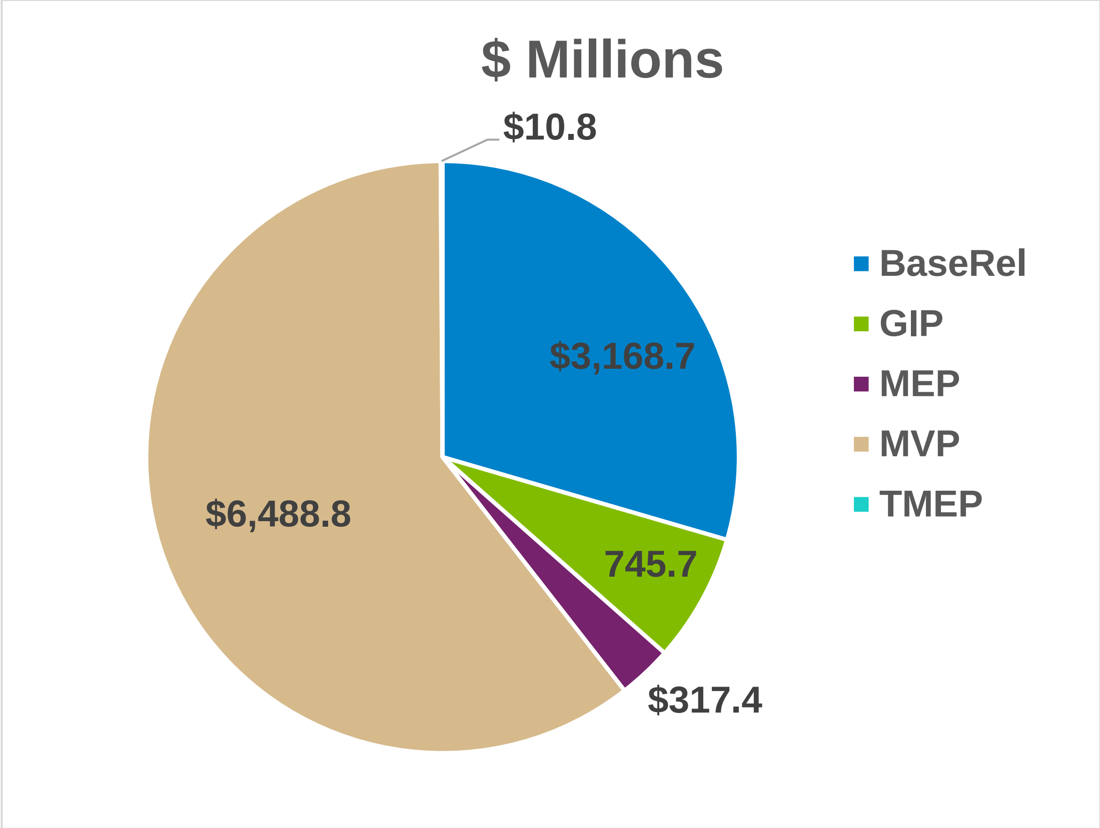


Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

Cost-Shared Project Type	BaseRel ($M)	GIP ($M)	MEP ($M)	MVP ($M)	TMEP ($M)	Total ($M)
A in MTEP06	$583.6	$68.9	$0	$0	$0	$652.5
A in MTEP07	$180.9	$34.4	$0	$0	$0	$215.2
A in MTEP08	$1,392.9	$33.3	$0	$0	$0	$1,426.2
A in MTEP09	$165.0	$102.3	$5.6	$0	$0	$272.9
A in MTEP10	$41.1	$5.0	$0	$504.0	$0	$550.1
A in MTEP11	$397.0	$72.8	$0	$5,984.8	$0	$6,454.6
A in MTEP12	$408.2	$53.9	$12.0	$0	$0	$474.1
A in MTEP13	$0	$8.0	$0	$0	$0	$8.0
A in MTEP14	$0	$35.4	$0	$0	$0	$35.4
A in MTEP15	$0	$15.0	$62.1	$0	$0	$77.2
A in MTEP16	$0	$67.1	$108.0	$0	$0	$175.1
A in MTEP17	$0	$163.9	$129.7	$0	$6.3	$299.8
A in MTEP18	$0	$85.8	$0	$0	$4.5	$90.2
Total	**$3,168.7**	**$745.7**	**$317.4**	**$6,488.8**	**$10.8**	**$10,731.3**

Table 2.2-2: MTEP06 to MTEP18 cost-shared project costs by MTEP cycle and project type (shown in $millions)

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.69 per month over the next 20 years

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[6] (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 2019 to 2054 and are shown by the blue line (Figure 2.2-2).[7] 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 $1.69 per month over the next 20 years.

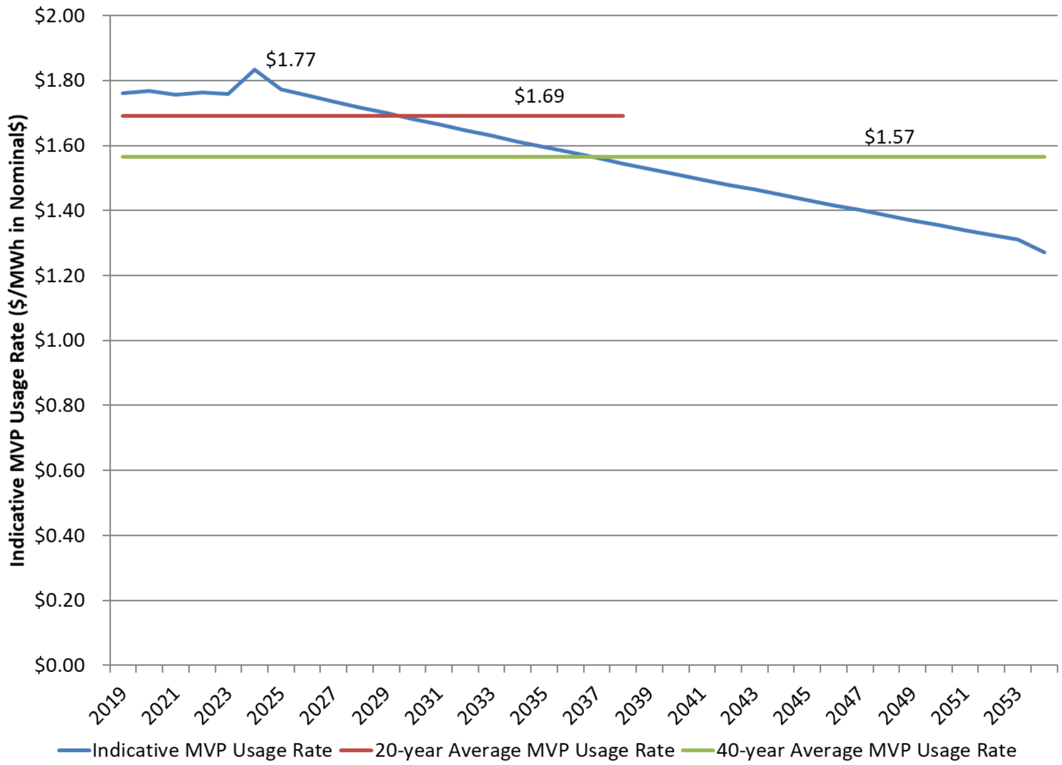


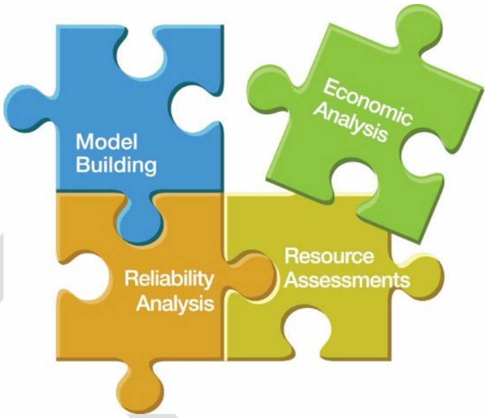
Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2019 to 2054

[6] 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.

[7] The annual estimated MVP Usage Rates for 2018 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 public website.

2.3 MTEP18 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 recommended projects for inclusion in MTEP18 Appendix A go before MISO's Board of Directors December meeting for official approval.

MTEP is MISO's annual process to study and recommend transmission expansion projects based on reliability, economic and public policy needs 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.

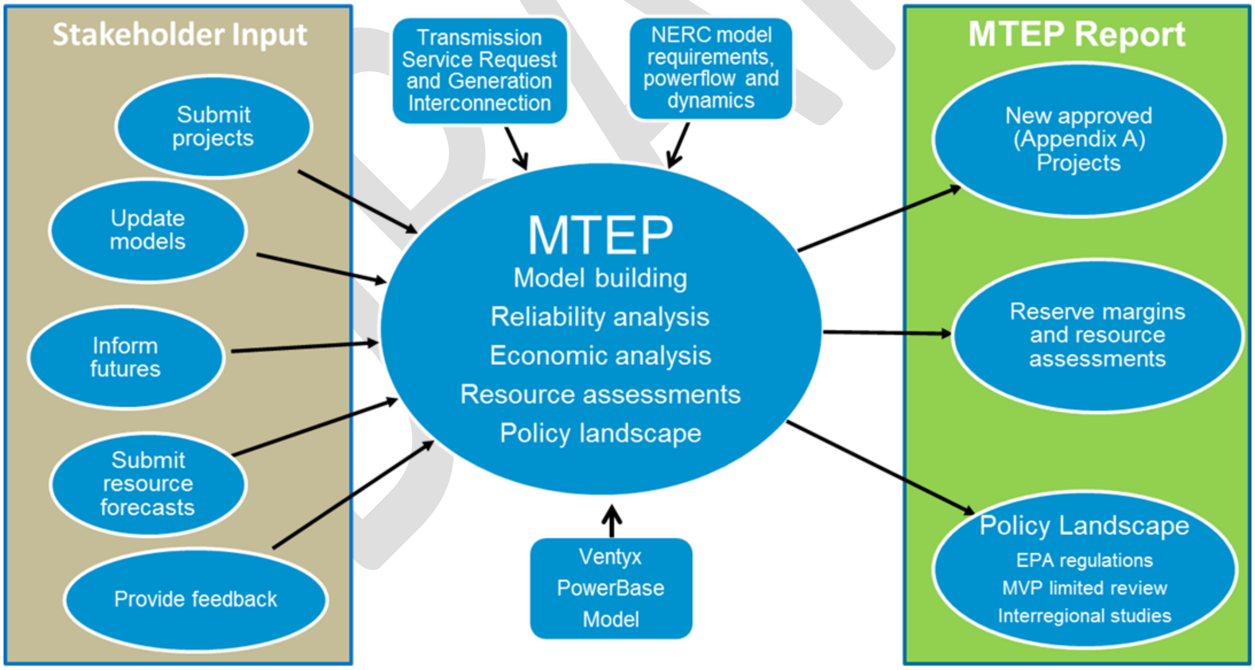


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

MISO's Value-Based Planning Approach incorporates multiple perspectives by conducting reliability and economic analyses. MISO 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).

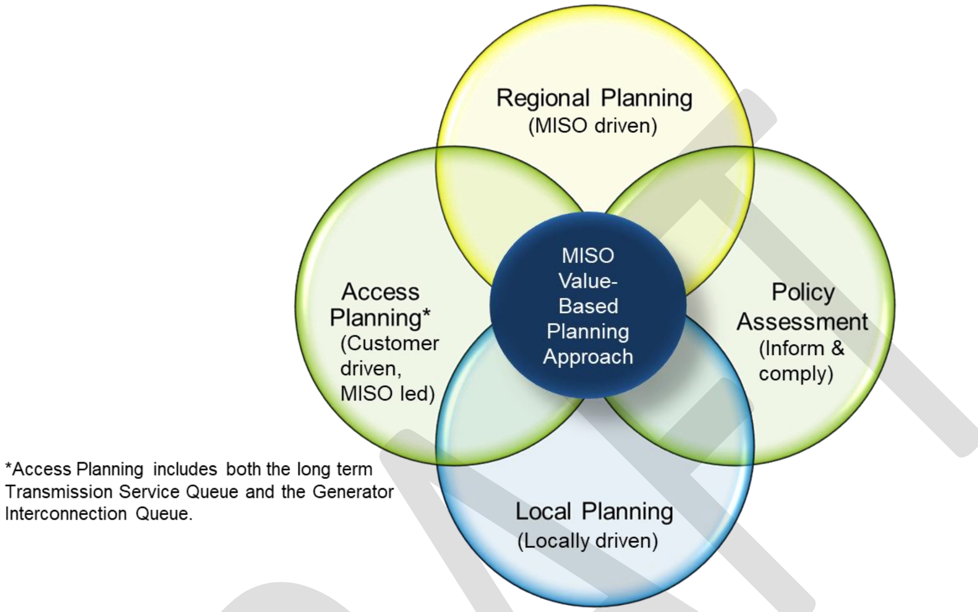


Figure 2.3-2: MISO's value-based planning approach

MTEP18 Workstreams

Completion of MTEP18 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.

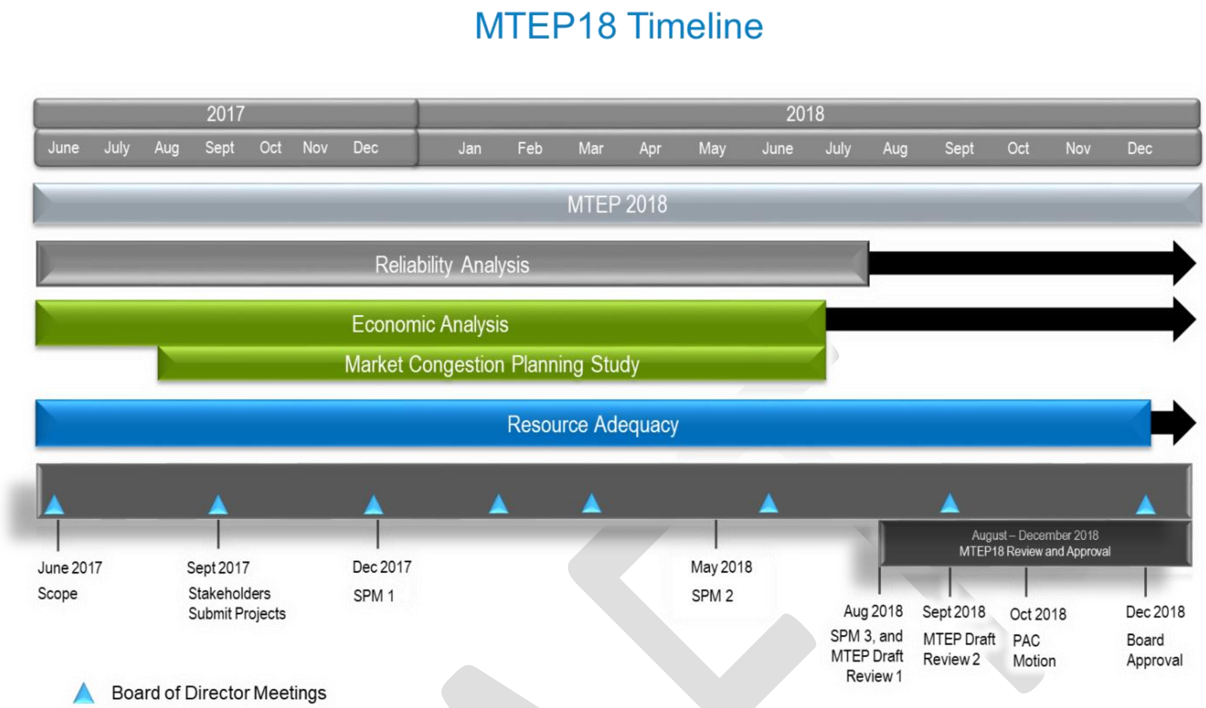


Figure 2.3-3: MTEP18 timeline

Stakeholder Involvement in MTEP18

Stakeholders provide model updates, project submissions, input on appropriate assumptions and comments on results and report drafts. This feedback occurs through a series of stakeholder forums. Each of the four MISO subregions holds 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 and effectiveness for each project. Some projects may also use stakeholder Technical Study Task Forces (TSTF) as needed 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

MTEP18 Schedule

Each MTEP cycle spans 18 months. MTEP18 began June 2017 and ends December 2018, with Board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP18 projects	September 2017
First round of Subregional Planning Meetings (SPM)	December 2017
Second round of Subregional Planning Meetings (SPM)	May 2018
MTEP18 Report first draft posted	August 2018
Third round of SPM meetings	August 2018
Planning Advisory Committee final review and motion	October 2018
MISO Board System Planning Committee review	November 2018
MISO Board of Directors meeting to consider MTEP18 approval	December 2018

Table 2.3-1: MTEP18 schedule, major milestones

A Guide to MTEP Report Outputs

The MTEP18 report is organized into four books and a series of detailed appendices.

- Book 1 summarizes this cycle's projects and the analyses supporting the recommendation of these projects
- 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 its 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 that have been validated by MISO as the preferred solution to address an identified need based on current information and forecasts, 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 MTEP18" 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
- Targeted Market Efficiency 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
Targeted Market Efficiency 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 in collaboration with MISO and stakeholders. MISO will conduct independent assessment on effectiveness of all bottom-up projects and alternatives submitted by Transmission Owners and stakeholders and determine 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 and regional reliability standards. Since MTEP13, Baseline Reliability Projects are no longer cost shared.
- **Other Projects** address a wide range of localized 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 driven by one of the following factors: clearance, condition, load interconnection, 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, Multi-Value Projects, and Targeted Market Efficiency 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 neighboring 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 of 1.25 or greater.
- **Targeted Market Efficiency Projects (TMEP)** are interregional projects, with PJM, that address historical Market-to-Market congestion along the MISO-PJM seam. TMEPs are low cost, quick implementation upgrades that complement the existing Order 1000 interregional project types.

Externally Driven Projects

Externally driven projects are 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.[8] 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 in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[9]. 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.

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 recommended 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 that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, 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 as to the prudence of selecting this project over an alternative

[8] 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.
[9] http://www.nerc.net/standardsreports/standardssummary.aspx

project given potential changes in projected future conditions. 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 in order to:

- Remove the projects that will be recommended for approval in the current cycle, or was previously included to address identified system needs that no longer exist, or is determined to no longer be the best solution to an identified need
- Add new bottom-up projects in the current cycle that have been determined to be the preferred solution

2.5 MTEP18 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. MISO coordinates its MTEP models with neighboring entities, so as to have accurate representation of adjacent systems.

MTEP18 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 MTEP18 model development process. In addition to NERC Standard TPL-001-4 requirements, MISO built a powerflow and dynamic models suite to support the Eastern Interconnection modeling process per MOD-032 requirements. For the MTEP18 planning process, MISO built two sets of powerflow models. One model set, called Appendix A Only, contained approved future projects from MTEP17 Appendix A. The other model set, called Target A, contained approved MTEP17 Appendix A projects and projects targeted for approval in MTEP18.

For MTEP studies, models for steady-state powerflow and dynamic 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, for external area representation
- ASEA Brown Boveri (ABB) PROMOD PowerBase database
- External model updates from neighboring planning entities

MTEP models are interdependent with multiple major data inputs within the process (Figure 2.5-1).

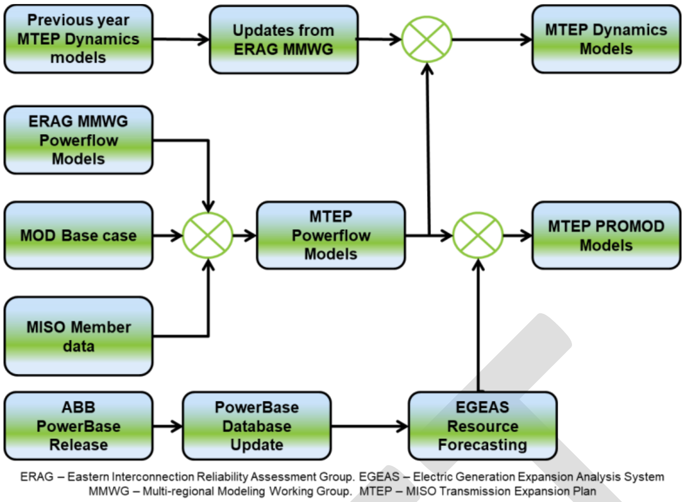


Figure 2.5-1: MTEP model relationships

Reliability Study Models - Powerflow Models

MISO developed regional powerflow models for MTEP18 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[10]. The table includes renewable wind resource levels at percent of nameplate. All models assume solar generation at 50 percent of nameplate except Light Load models, which are modeled at 0 percent.

Model Year	Base case	Sensitivity
Year 2	2020 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2020 Light Load (minimum load level) wind at 0% (*TPL requirement R2.1.4*)
Year 5	2023 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2023 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.1.4*)
Year 5	2023 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.1.2*)	2023 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.1.4*)
Year 5	2023-2024 Winter Peak with wind at 40%	
Year 10	2028 Summer Peak with wind at 15.6% (*TPL requirement R2.2.1*)	

Table 2.5-1: MTEP18 powerflow models

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.

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

- 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:
    - MTEP17 Appendix A Only: These models include only approved future transmission facilities first approved in MTEP17 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.
    - MTEP17 Appendix A plus MTEP18 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 MTEP18 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 the unit can be retired.

LBA Generation Dispatch Methodology

The generation dispatch in steady-state powerflow models is done at the Local Balancing Authority (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 except Light Load models, which are modeled at 0 percent. 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 MW 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 LBA for 2020 summer and 2023 summer peak models are shown in Table 2.5-2. There may be differences in the load values for each area from Module E load values due to inclusion of station service loads and non-member loads contained within the MISO members' model areas.

Area	2020 Summer Peak (All values in MW)				2023 Summer Peak (All values in MW)			
	Generation	Load	Losses	Area Interchange	Generation	Load	Losses	Area Interchange
HE	1,369	688	41	640	1,368	695	41	633
DEI	6,907	7,193	284	(578)	7,048	7,254	287	(500)
SIGE	2,016	1,790	33	193	2,038	1,799	32	207
IPL	3,459	2,837	69	549	3,737	2,887	69	777
NIPS	3,354	3,678	79	(408)	3,394	3,731	73	(415)
METC	11,275	10,039	303	934	11,609	10,065	326	1218
ITCT	10,867	11,319	231	(683)	10,544	11,196	236	(888)
WEC	6,567	6,788	104	(340)	6,565	6,810	101	(362)
MIUP	571	533	22	14	571	534	22	13
BREC	1,378	1,631	20	(274)	1,368	1,635	18	(286)
EES-EMI	4,053	3,933	109	5	3,923	3,966	105	(155)
EES-EAI	9,159	7,410	158	1583	9,266	7,415	153	1690
LAGN	1,292	1,834	7	(549)	1,291	1,950	8	(667)
CWLD	230	385	2	(157)	233	398	3	(167)
SMEPA	1,240	809	20	412	1,386	845	20	521
EES	19,083	19,477	345	(850)	19,638	19,906	332	(712)
AMMO	8,504	8,227	182	95	8,855	8,325	189	341
AMIL	10,295	9,557	248	490	10,350	9,510	237	603
CWLP	474	424	3	47	467	418	3	46
SIPC	358	344	10	4	374	353	10	10
CLEC	3,693	3,121	82	490	3,705	3,124	91	490
LAFA	191	502	9	(320)	191	516	6	(331)
LEPA	82	180	0	(98)	82	180	0	(98)
XEL	9,695	10,361	244	(932)	9,903	10,595	237	(952)
MP	1,315	1,522	74	(283)	1,342	1,559	69	(287)
SMMPA	125	602	2	(479)	121	607	2	(488)
GRE	2,678	2,891	93	(309)	2,761	3,012	95	(349)
OTP	2,133	2,046	94	(11)	2,130	2,167	97	(138)
ALTW	4,023	4,020	84	(81)	4,119	4,131	85	(97)
MPW	260	162	2	97	255	165	2	89
MEC	5,989	5,980	84	(74)	6,077	6,291	85	(300)
MDU	467	615	13	(162)	467	636	13	(182)
BEPC-MISO	6	92	-	(86)	6	94	-	(89)
DPC	812	1,050	38	(276)	812	1,065	39	(291)
ALTE	3,859	2,851	71	931	4,168	2,940	76	1146
WPS	2,553	2,607	50	(109)	2,524	2,649	48	(179)
MGE	293	708	10	(427)	233	711	10	(490)
UPPC	46	215	4	(173)	50	217	4	(171)
Total	**140,669**	**138,420**	**3,221**	**(1,177)**	**142,970**	**140,351**	**3,224**	**(810)**

Table 2.5-2: System conditions for 2020 and 2023 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	2018 Summer Peak with wind at 15.6%	
Year 5	2023 Summer Peak with wind at 15.6% (*TPL requirement R2.4.1*)	2023 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.4.3*)
Year 5	2023 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.4.2*)	2023 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.4.3*)

Table 2.5-3: MTEP18 dynamic stability models

The MTEP17 dynamics data is the starting point for MTEP18 dynamics model development. This data is reviewed and updated with stakeholder feedback. Additionally, the ERAG MMWG 2017 series dynamic stability models are reviewed and any improved modeling data in external areas is incorporated in the MTEP18 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 MTEP18 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 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 MTEP18 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 MTEP18, the Planning Advisory Committee (PAC) approved the following future scenarios:[11]

- Limited Fleet Change
- Continued Fleet Change
- Accelerated Fleet Change
- Distributed and Emerging Technologies

[11] For more details on these assumption scenarios, see Sections 5.2: MTEP Futures 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 MTEP18 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
- Publicly announced generation retirements
- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff — see Section 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 2017. 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).

Section 3: Historical MTEP Plan Status

3.1 MTEP Approved Appendix A 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-approved Appendix A projects as of MISO's third quarter, September 30, 2018, 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 2018, MISO was tracking 1,157 active projects totaling $9 billion of approved investment. Of the total active investment, 38 percent of the projects were approved in MTEP17 and the remaining 62 percent were approved in MTEP03 through MTEP16. Since the first MTEP report in 2003, a total of $36 billion in transmission projects have been approved. Of this approved investment, $19.1 billion have been constructed; $4.4 billion have been withdrawn; and the remaining $12.3 billion are in various stages of design, planning or construction through the third quarter of 2018.

Following the approval of an 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.

MISO tracks the status of these projects (Figure 3.1-1) along with the total current investment for each MTEP cycle. The most common facility type based on investment is line on new right-of-way (ROW) (47 percent) followed by substation projects (36 percent) and line upgrades (17 percent) (Figure 3.1-2).

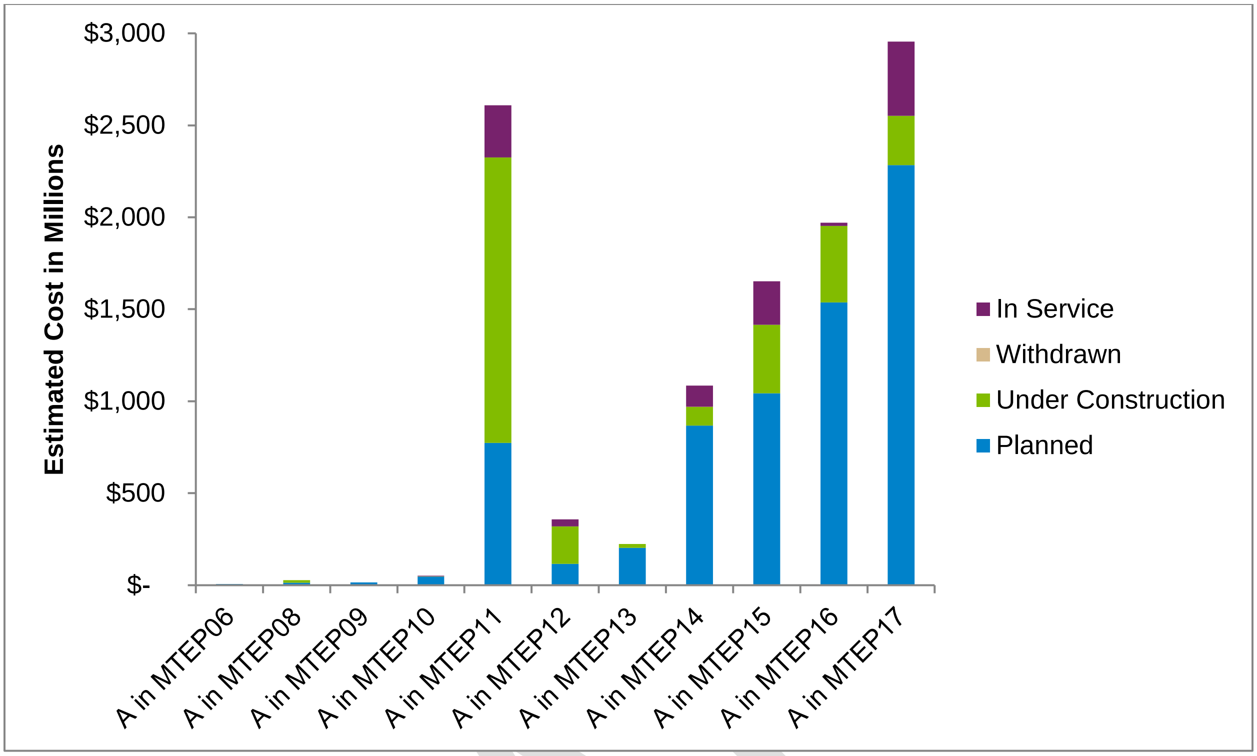


Figure 3.1-1: Project status of active projects

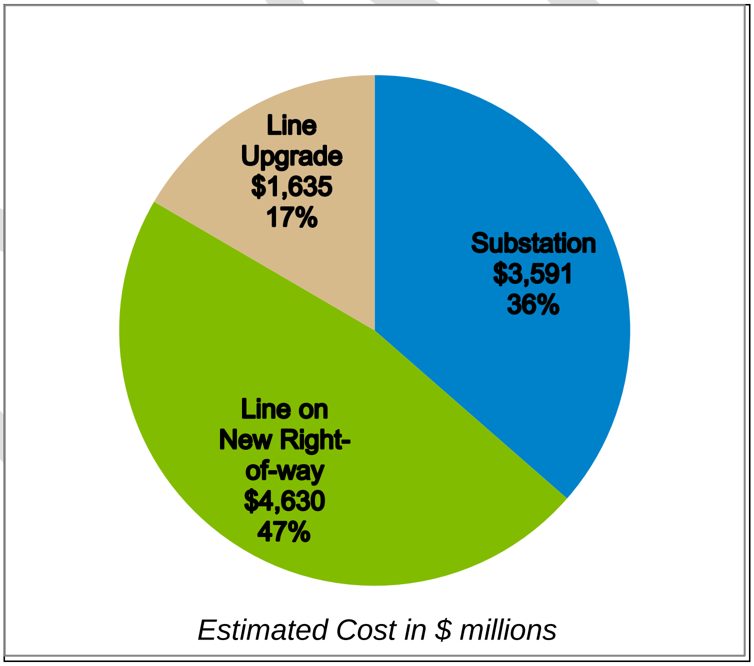


Figure 3.1-2: Facility cost of active projects

Multi-Value Project Portfolio Status

The Multi-Value Projects (MVP) 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[12]:

- 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

As of September 2018, 10 MVPs are in service, six are at least partially under construction and the remainder are in progress with state regulatory approvals (Figure 3.1-3).

The MVP dashboard is updated quarterly. The most up-to-date version can be found on the MISO website.

[12] Source: Candidate MVP Report. A review of the MVP Portfolio's benefits is contained in Section 7.2: MVP Limited Review.

MVP No.	Project Name	State	Estimated in Service Date[1]		Status		Cost[2]			Explanation[6]
			MTEP Approved	September 2018	State Regulatory Status	Construction	MTEP Approved[3]	MTEP Approved Dollars Adjusted to Estimated ISD[4]	September 2018[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	●	Complete	$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	$1,034	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	$274	
7	Ottumwa - Zachary	IA/MO	2017-2020	2018-2019	●	Pending	$152	$186	$223	A,B,C,D
8	Zachary - Maywood	MO	2016-2018	2016-2019	●	Underway	$113	$137	$175	A, D, E
9	Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin	MO/IL	2016-2017	2016-2017	●	Complete	$432	$501	$723	A, B
10	Austin - Pana	IL	2018	2016-2017	●	Complete	$99	$115	$135	A,B
11	Pana - Faraday - Kansas - Sugar Creek	IL/IN	2018-2019	2015-2019	●	Underway	$318	$388	$404	A,B
12	Reynolds - Burr Oak - Hiple	IN	2019	2018	●	Underway	$271	$322	$405	B,C
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	$510	$563	$504	
14	Reynolds - Greentown	IN	2018	2013-2018	●	Complete	$245	$299	$348	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	●	Complete	$199	$237	$201	
17	Sidney - Rising	IL	2016	2016	●	Complete	$83	$94	$88	
						Total	$5,564	$6,573	$6,577	

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 (https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=1945).
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 September 2018

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 MTEP18 cycle, the MTEP report now represents 15 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; public policy and regulations; emerging new technologies; 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 and reflect the changes in the following quarterly project status reports.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP18 cycle, is more than $35 billion (Figure 3.2-1). MTEP18 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.

- $4.3 billion of MTEP projects are expected to go into service in 2018

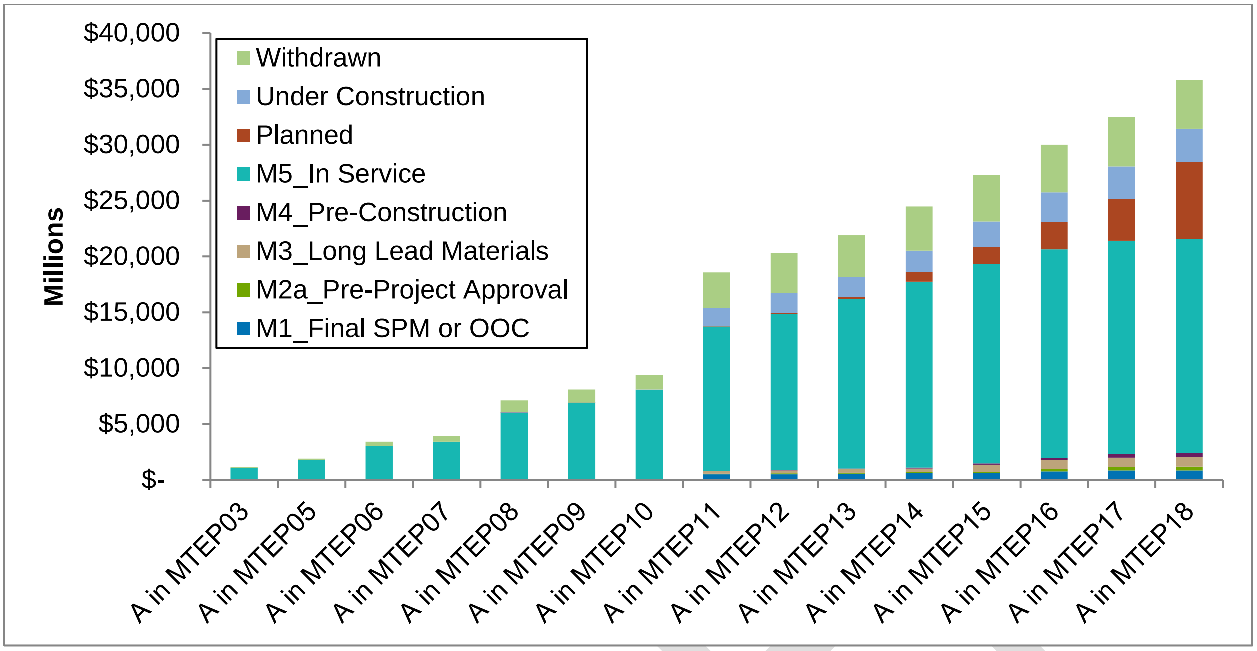


Figure 3.2-1: Cumulative transmission investment by facility status[13]

The historical perspective of 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 periodic updating of the transmission plans. Approval of the Multi-Value Projects (MVP) portfolio explains the large increase between MTEP10 and MTEP11.

Highlights or points of interest in prior MTEP cycles include:

- 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 increased as projects were 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.
- Beginning in MTEP15, MTEP participants began planning to meet a series of new, more stringent NERC reliability standards
- MTEP16, MTEP17 and MTEP18 further reflect a continuation of a typical MTEP, primarily driven by reliability projects

[13] Project milestones described in Section 3.1: Prior MTEP Plan Status

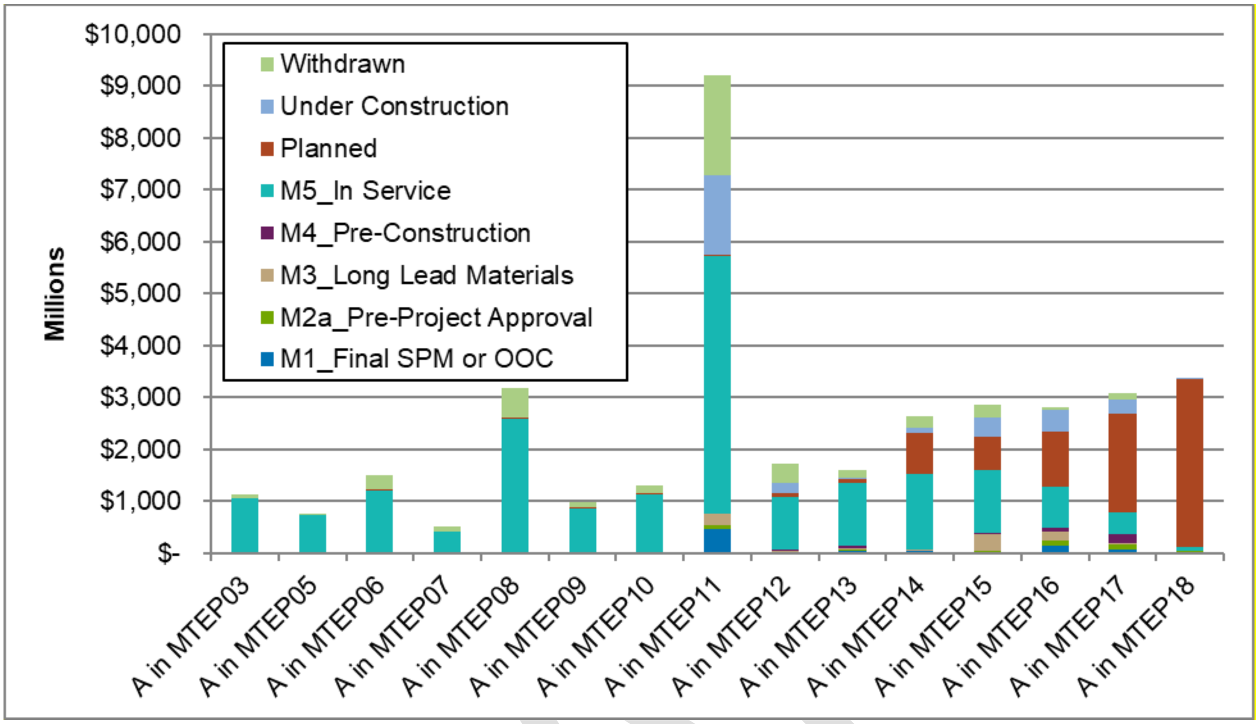


Figure 3.2-2: Approved transmission investment by MTEP cycle[14]

Since MTEP03, approximately $4.4 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.

[14] New Appendix A projects in the MTEP18 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.

Section 4: Reliability Analysis

4.1 Reliability Assessment and Compliance

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

Continued reliability of the transmission system is measured by compliance with applicable NERC and regional reliability standards 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 2017, May-June 2018 and August 2018. 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.

This section summarizes the MTEP18 reliability assessment; read the complete results in Appendix D.

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 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

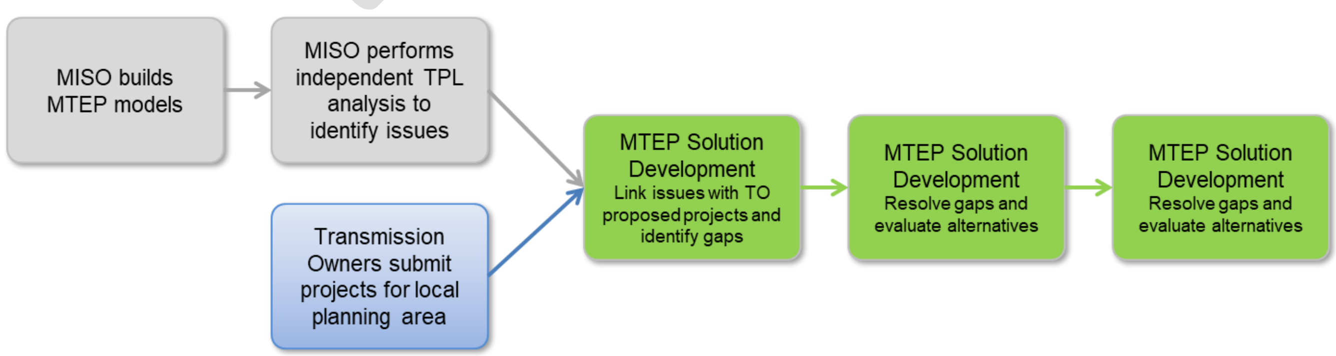


Figure 4.1-1: MTEP18 Reliability Study Process

Models

In MTEP18, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with its stakeholders:

- 2020 Summer Peak (wind at 15 percent, solar at 50 percent)
- 2020 Light Load (wind at 0 percent, solar at 0 percent)
- 2023 Summer Peak (wind at 15 percent, solar at 50 percent)
- 2023 Shoulder Peak (wind at 40 percent, solar at 50 percent)
- 2023 Shoulder Peak (wind at 90 percent, solar at 50 percent)
- 2023 Winter Peak (wind at 40 percent, solar at 50 percent)
- 2028 Summer Peak (wind at 15 percent, solar at 50 percent)

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP18 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 2017 series Multiregional Modeling Working Group (MMWG) interchange.[15] MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

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

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 percent to 90 percent of nameplate in the shoulder cases. These wind dispatch levels were selected through the MISO planning stakeholder process. Read more about the models in Appendix D2 of this report.

NERC Reliability Assessment

MISO conducts baseline reliability studies to ensure the transmission system is planned to comply with the following planning standards and criteria:

- Applicable North American Electric Reliability Corp. (NERC) reliability standards

[15] https://rfirst.org/ProgramAreas/RAPA/ERAG/MMWG/Pages/MMWG.aspx

- 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)

The NERC reliability assessment, performed by MISO, identifies potential thermal and voltage reliability issues. MISO and its TOs are required to develop and implement solutions for each identified violation of applicable planning standards and criteria. 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 solutions to longer term system issues are investigated further in subsequent MTEP cycles when solutions lead times allow.

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 MTEP18 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 MTEP18 2020 summer peak and shoulder peak models; the 2023 summer peak, shoulder peak, winter peak and light-load models; and the 2028 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 MTEP18 2023 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 power/voltage (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.

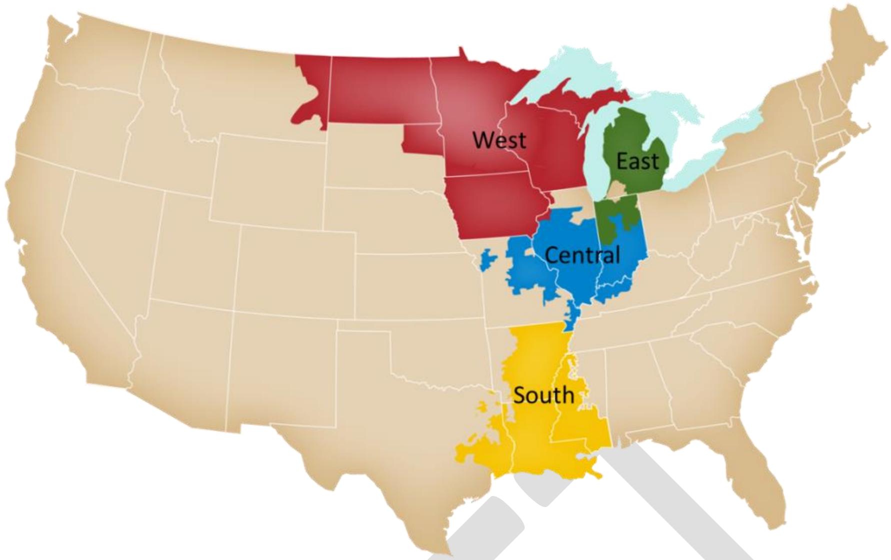


Figure 4.1-2: MISO planning subregions

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
12/6/2017	East SPM No. 1	Detroit, MI
12/8/2017	West SPM No. 1	Eagan, MN
12/11/2017	South SPM No. 1	Metairie, LA
12/12/2017	Central SPM No. 1	Carmel, IN
1/25/2018	West TSTF	Conf. Call
1/26/2018	South TSTF	Conf. Call
3/2/2018	South TSTF	Conf. Call
5/18/2018	East TSTF	Jackson, MI
5/25/2018	Central SPM No. 2	Carmel, IN
5/30/2018	South SPM No. 2	Metairie, LA
5/31/2018	East SPM No. 2	Novi, MI
6/1/2018	West SPM No. 2	Eagan, MN
7/31/2018	West TSTF	Conf. Call
8/7/2018	East TSTF	Livonia, MI
8/23/2018	South SPM No. 3	Metairie, LA
8/28/2018	Central SPM No. 3	Carmel, IN
8/29/2018	West SPM No. 3	Eagan, MN
8/30/2018	East SPM No. 3	Cadillac, MI

Table 4.1-1: MTEP18 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 MTEP18 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 MTEP18 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.

MTEP18 contains Target Appendix A GIPs totaling approximately $255 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 ($)
13619	New Ruby 345 kV breaker substation	AMIL	Shared	Central	$8,425,441
13769	J704/J711 GIC – Silver River substation Interconnection and Network Upgrades	ATC	Shared	ATC	$19,700,000
13784	J703 GIC – Huron substation, Interconnection and Network Upgrades	ATC	Shared	ATC	$17,100,000
13796	J515 - Cayuga CT 345 kV breaker substation	DEI	Shared	Central	$3,511,382
14024	J041 – Generator Interconnection	ITCM	Not Shared	West	$7,751,624
14025	J438 – FCA Affected Systems Upgrade	ITCM	Not Shared	West	$2,386,020
14030	J407 - Generator Interconnection	ITCM	Not Shared	West	$3,383,715
14032	J449 – Generator Interconnection	ITCM	Not Shared	West	$60,000
14204	J704/J711 GIC – Silver River substation Interconnection and Network Upgrades	ATC	Shared	ATC	$18,700,000
14625	J475/J555 North English	MEC	Shared	West	$2,750,000
14626	J438 English Farms	MEC	Not Shared	West	$4,800,000
14744	Lake Charles Power Station Deliverability Projects	EES	Not Shared	South	$50,681,159
14745	Montgomery County Power Station Deliverability Projects	EES	Not Shared	South	$98,969,890
14925	J505 GIC, Apollo substation, Generator Interconnection and Network Facilities	ATC	Shared	ATC	$8,300,000
15493	J538 GIC – Knowles 138 kV breaker substation	METC	Not Shared	East	$6,920,000
15496	J533 GIC – Slate 345 kV breaker substation	METC	Not Shared	East	$1,456,000
Total Estimated Cost					**$ 254,895,231**

Table 4.2-1 Generation Interconnection Projects in MTEP18 Target Appendix A[16]

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

GI Project No.	TO	County	State	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
J704	ATC	Baraga	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Silver River 138 kV Substation	54.9	Gas	GIA
J703	ATC	Marquette	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Huron 138 kV Substation	128.1	Gas	GIA
J711	ATC	Baraga	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Silver River 138 kV Substation	130	Wind	GIA
J505	ATC	Manitowoc	WI	DPP-2016-FEB-ATC	NRIS	Apollo 138 kV Substation	99	Solar	GIA
J468	AMIL	Douglas	IL	DPP-2016-FEB-Central	NRIS	Ruby 345kV Line	202	Wind	GIA
J484	EES	Calcasieu	LA	DPP-2016-AUG-South	NRIS	Nelson Power Station	1056.19	CCT	*
J515	DEI	Benton & Warren	IN	DPP-2016-FEB-Central	ERIS	Cayuga 345 kV Substation	400	Wind	GIA
J472	EES	Montgomery	TX	DPP-2016-AUG-South	NRIS	Lewis Creek 138 kV and 230 kV Substations	1044.8	Gas	GIA
J041	ITCM	Grundy	IA	DPP-2015-AUG-West	NRIS	Wellsburg 161 kV Substation	90	Wind	GIA
J438	MEC	Poweshiek	IA	DPP-2015-AUG-West	NRIS	Poweshiek-Parnell 161 kV Line	170	Wind	GIA
J407	ITCM	Freeborn	MN	DPP-2015-FEB-West	NRIS	Glenworth 161 kV Substation	200	Wind	GIA
J449	ITCM	Mitchell	IA	DPP-2015-AUG-West	NRIS	Pioneer Prairie I 345 kV Substation	202	Wind	GIA
J475	MEC	Poweshiek	IA	DPP-2016-FEB-West	NRIS	Montezuma 345 kV Substation	200	Wind	GIA
J555	MEC	Poweshiek	IA	DPP-2016-AUG-West	NRIS	Montezuma 345 kV Substation	140	Wind	GIA
J538	METC	Hillsdale	MI	DPP-2016-FEB-MI	NRIS	Knowles 138kV breaker substation	150	Wind	GIA
J533	METC	Gratiot	MI	DPP-2016-FEB-MI	NRIS	Slate 345kV breaker substation	200	Wind	GIA

***GIA in process**

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

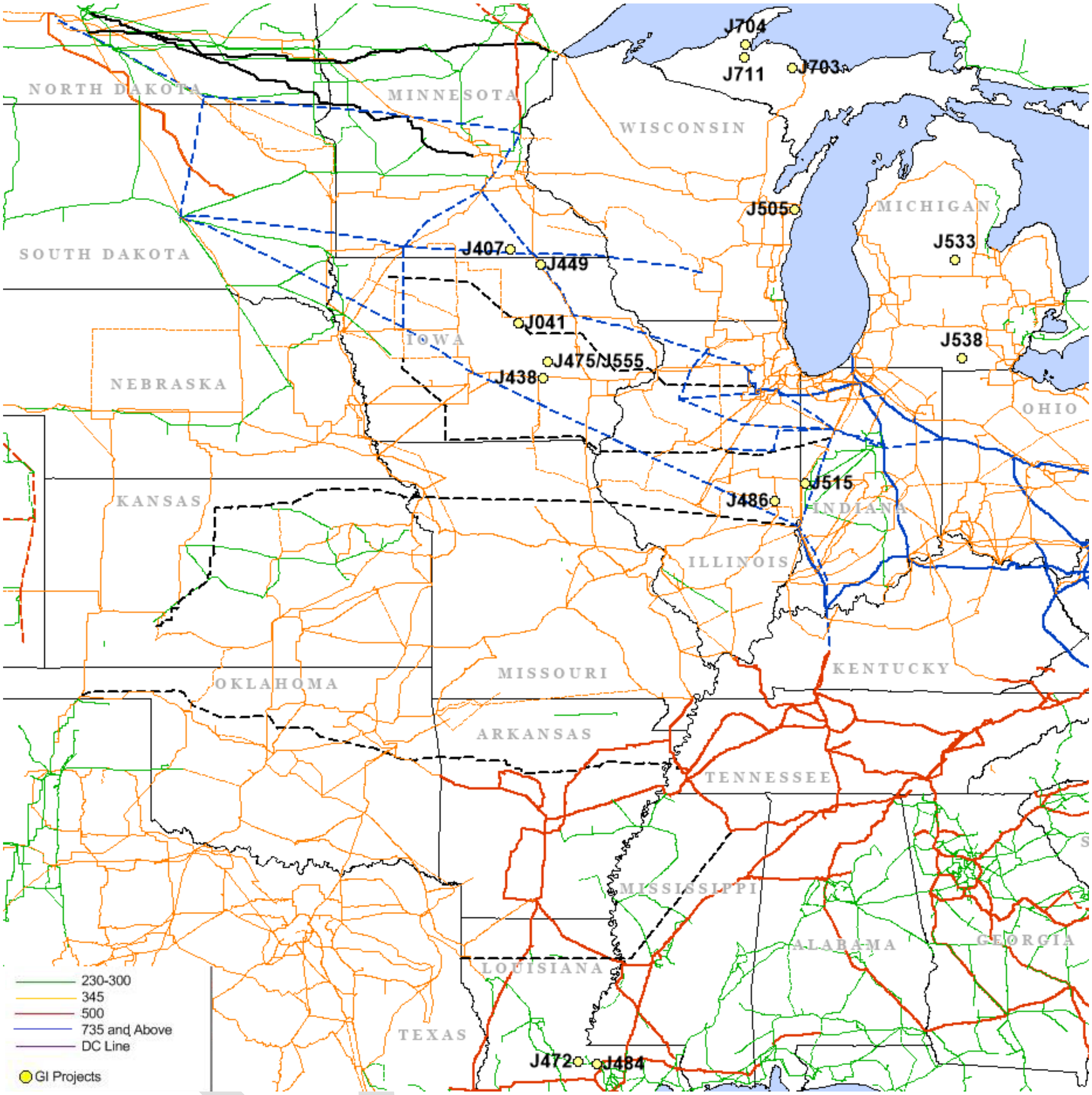


Figure 4.2-1: Generation Interconnection Requests associated with MTEP18 Target Appendix A

MTEP18 Target Appendix A

MTEP Project 13619 – Ameren Electric Service Co.

- Perform network upgrades for J468 GIP
- J468 – 202 MW Wind Generator
- Point of interconnection: Ruby 345 kV Substation
- Construct a three-position initial (six-position ultimate), 3000 A 345 kV switching station in a ring bus configuration at structure 100 in the Kansas-Sidney 345 kV line 4560 for the interconnection of Broadlands Wind Farm.
- Anticipated completion date: October 1, 2019
- Anticipated cost: $8,425,441

MTEP Project 13769 – American Transmission Co.

- Perform network upgrades for J704 GIP
- J704 – 54.9 MW Gas Generator
- Point of interconnection: Silver River 138 kV Substation
- Construct a new eight-position 138 kV Silver River Substation in a breaker-and-a-half configuration adjacent to the Silver River substation.
- Anticipated completion date: January 31, 2019
- Anticipated cost: $19,700,000

MTEP Project 13796 – Duke Energy Corporation

- Perform network upgrades for J515 GIP
- J515 – 400 MW Wind Generator
- Point of interconnection: Cayuga 345 kV Substation
- Cayuga CT 345kV Ring Bus Expansion - to accommodate wind farm connection - J515
- Anticipated completion date: June 1, 2019
- Anticipated cost: $3,511,382

MTEP Project 13784 – American Transmission Co.

- Perform network upgrades for J703 GIP
- J703 – 128.1 MW Gas Generator
- Point of interconnection: Huron 138 kV Substation
- Construct a new six-position 138-kV Huron Substation in a breaker-and-a-half configuration constructed adjacent to the new power plant. The substation will: be designed for a 10-position ultimate design; tie in the Freeman-National 138 kV (FREG11) and Presque Isle – Empire (Goose Lake) 138 kV lines creating a double circuit loop.
- Anticipated completion date: January 23, 2019
- Anticipated cost: $17,100,000

MTEP Project 14024 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J041 GIP
- J041 – 90 MW Wind Generator
- Point of interconnection: Wellsburg 161 kV Substation
- Rebuild Wellsburg 161 kV to a breaker-and-a-half configuration; customer-dedicated facilities at Wellsburg (TOIF); 161 kV Line relocation; and Newton to Maytag terminal upgrade at Newton
- Anticipated completion date: September 1, 2019
- Anticipated cost: $7,751,624

MTEP Project 14025 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J438 GIP

- J438 – 170 MW Wind Generator
- Point of interconnection: Poweshiek-Parnell 161 kV Line
- Replace existing 161/69 kV transformer at Poweshiek
- Anticipated completion date: December 14, 2018
- Anticipated cost: $2,386,020

MTEP Project 14030 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J407 GIP
- J407 – 200 MW Wind Generator
- Point of interconnection: Glenworth 161 kV Substation
- Expand 161 kV ring and add a 161 kV terminal at Glenworth; customer dedicated facilities at Glenworth; Replace Glenworth 161/69 kV transformer with a 150 MVA unit
- Anticipated completion date: August 7, 2020
- Anticipated cost: $3,383,715

MTEP Project 14032 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J449 GIP
- J449 – 202 MW Wind Generator
- Point of interconnection: Pioneer Prairie I 345 kV Substation
- Change relay settings at Mitchell County 345 to allow for project J449 interconnection via common facilities with existing project G172
- Completion date: July 1, 2018
- Cost: $60,000

MTEP Project 14204 – American Transmission Co.

- Perform network upgrades for J711 GIP
- J711 – 130 MW Wind Generator
- Point of interconnection: Silver River 138 kV Substation
- SILVER RIVERG22 and ATLANTIC69 line reroutes to accommodate generator lead line
- Anticipated completion date: September 23, 2020
- Anticipated cost: $18,700,000

MTEP Project 14625 – MidAmerican Energy Co.

- Perform network upgrades for J475/J555 GIP
- J475/J555 – 340 MW Wind Generator
- Point of interconnection: Montezuma 345 kV Substation
- Generator Interconnection Project
- Completion date: July 1, 2018
- Cost: $2,750,000

MTEP Project 14626 – MidAmerican Energy Co.

- Perform network upgrades for J438 GIP
- J438 – 170 MW Wind Generator
- Point of interconnection: Poweshiek-Parnell 161 kV Line
- Generator Interconnection Project
- Anticipated completion date: December 15, 2018
- Anticipated cost: $4,800,000

MTEP Project 14744 – Entergy - Louisiana

- Perform network upgrades for J484 GIP
- J484 – 1056.19 MW Gas CCT Generator
- Point of interconnection: Nelson Power Station

- Upgrade Nelson Substation equipment to 1958 MVA
- Rebuild the Nelson – Spanish Trail – Mossville 138 kV line
- Upgrade Alfol 69 kV Substation
- Upgrade Conoco 138 kV Substation
- Anticipated completion date: February 28, 2020
- Anticipated cost: $50,681,159

MTEP Project 14745 – Entergy - Texas

- Perform network upgrades for J472 GIP
- J472 – 1044.8 MW Gas Generator
- Point of interconnection: Lewis Creek 138 kV and 230 kV Substations
- Construct new 230 kV line from Lewis Creek to Porter with a minimum through path rating of 1956 Amps. Construct a 230 kV ring bus at Porter.
- Rebuild Lewis Creek – Goree 138 kV line section and upgrade terminal equipment to achieve a minimum through path rating of 1300 Amps. Rebuild Goree - Rivtrin 138 kV line section and upgrade terminal equipment to achieve a minimum through path rating of 1200 Amps.
- Reconductor/Rebuild Lewis Creek – Sheawill – Fort Worth Pipe 138 kV and upgrade terminal equipment to achieve a minimum through path rating of 1300 Amps.
- Cut in Mossville – Marshall 138 kV line into J634 substation. Upgrade J634 Tap – Mossville 138 kV to at least 168 MV
- Anticipated completion date: June 1, 2021
- Anticipated cost: $98,969,890

MTEP Project 14925 – American Transmission Co.

- Perform network upgrades for J505 GIP
- J505 – 99 MW Solar Generator
- Point of interconnection: Apollo 138 kV Substation
- Construct a new Apollo 138 kV substation to interconnect the J505 generation interconnection request. The new substation will be built as a three-position ring bus expandable to six positions. The new station will be located adjacent to the existing Kewaunee-Shoto 138 kV line.
- Loop in the existing Kewaunee-Shoto 138 kV line to the new station.
- Perform required remote end work at Kewaunee and Shoto substations
- Anticipated completion date: January 28, 2021
- Anticipated cost: $8,300,000

MTEP Project 15493 – Michigan Transmission Electric Transmission Co.

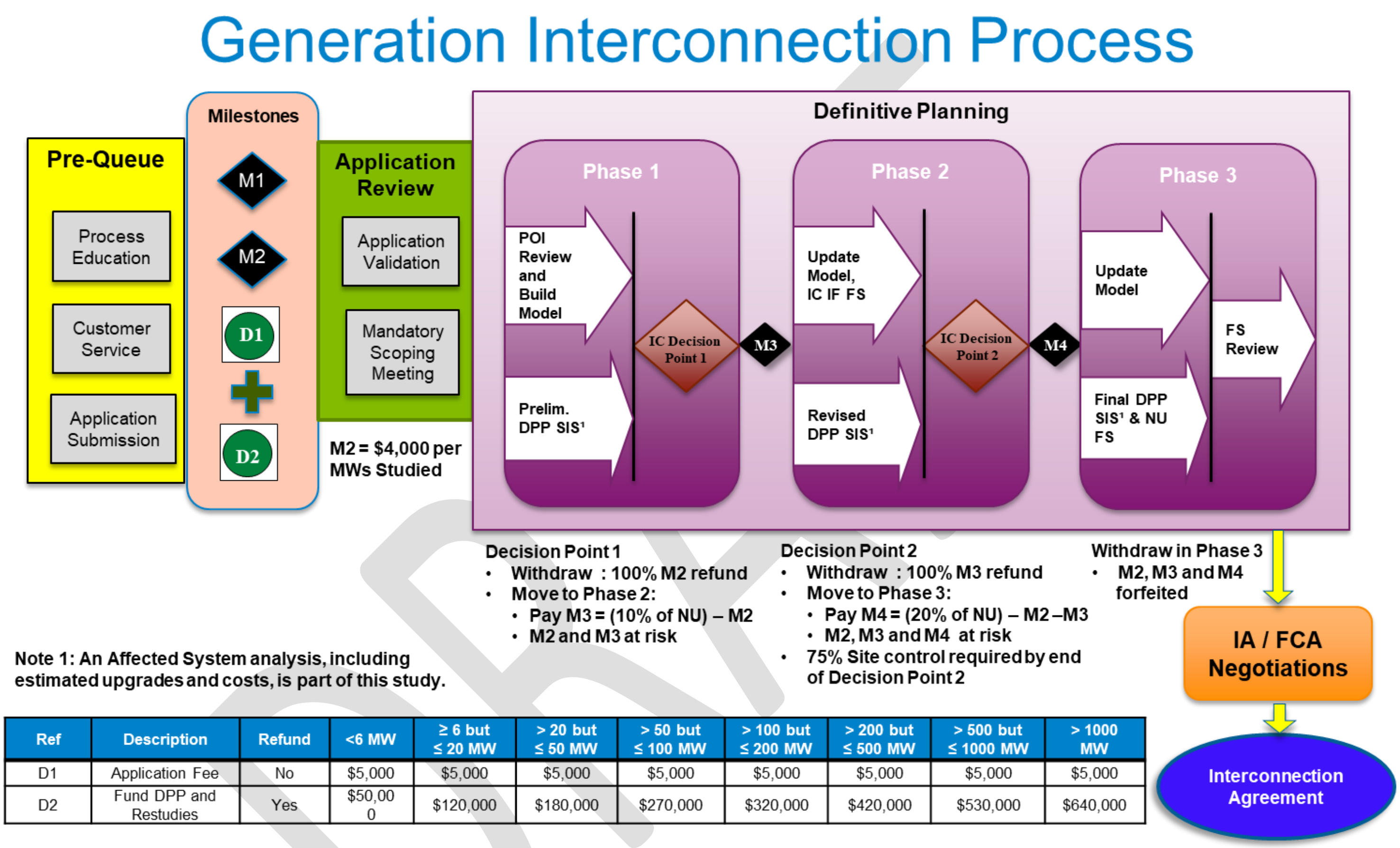
- Perform network upgrades for J538 GIP
- J538 – 150 MW Wind Generator
- Point of interconnection: Knowles 138 kV substation
- Construct a new Knowles 138 kV substation to interconnect the J538 generation interconnection request. The new substation will be built as a three-breaker ring bus. The new station will be located between the Moore Road and Beecher 138 kV line.
- Anticipated completion date: October 1, 2020
- Anticipated cost: $6,920,000

MTEP Project 15496 – Michigan Transmission Electric Transmission Co.

- Perform network upgrades for J533 GIP
- J533 – 200 MW Wind Generator
- Point of interconnection: Slate 345 kV Substation
- Install a 345 kV breaker at the Slate 345 kV substation
- Install two disconnects at the Slate 345 kV substation
- Anticipated completion date: October 1, 2019
- Anticipated cost: $1,456,000

The Queue Process

Interconnection requests to connect new generation to the transmission 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 2,371 generator interconnection requests totaling 442.8 GW (Figures 4.2-3, 4.2-4 and 4.2-5). Among them, 78.7 GW out of the 442.8 GW or 17.8 percent now have a Generation Interconnection Agreement (GIA). 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.

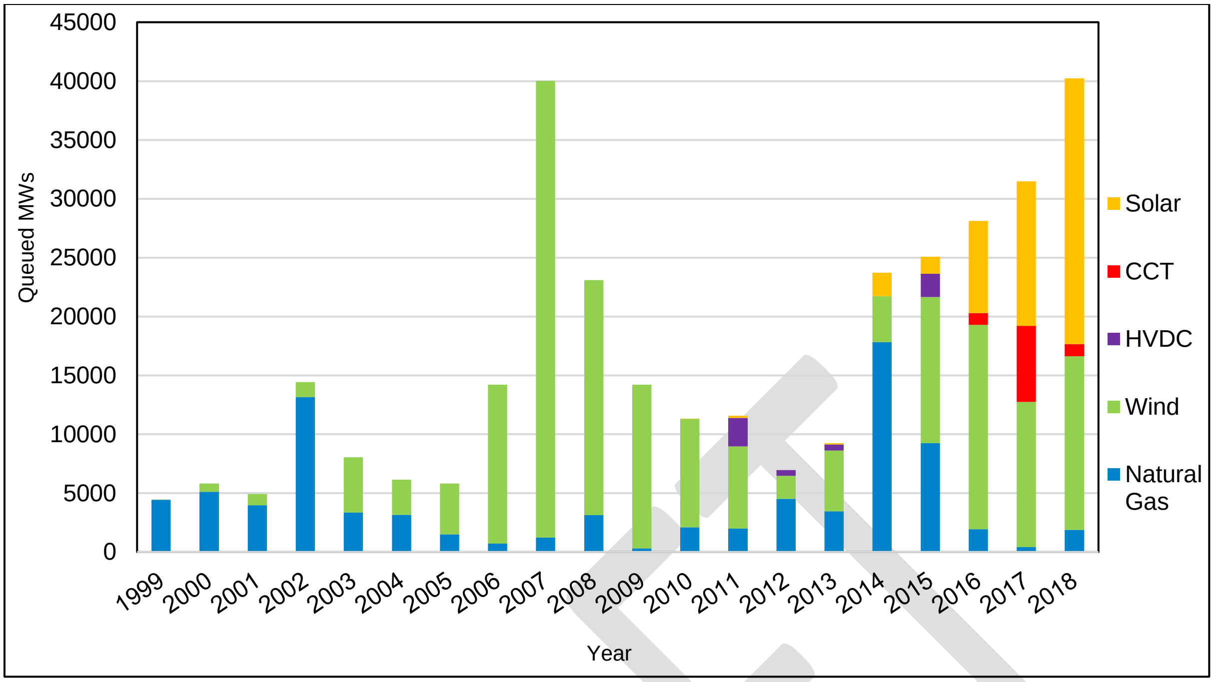


Figure 4.2-3: Queue Trends

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 and three territories have enforceable RPS or other mandated renewable capacity policies (Figure 4.2-4). In addition, eight states and one territory 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. The requests for wind have now stabilized in the last several years in the MISO footprint (Figure 4.2-5).

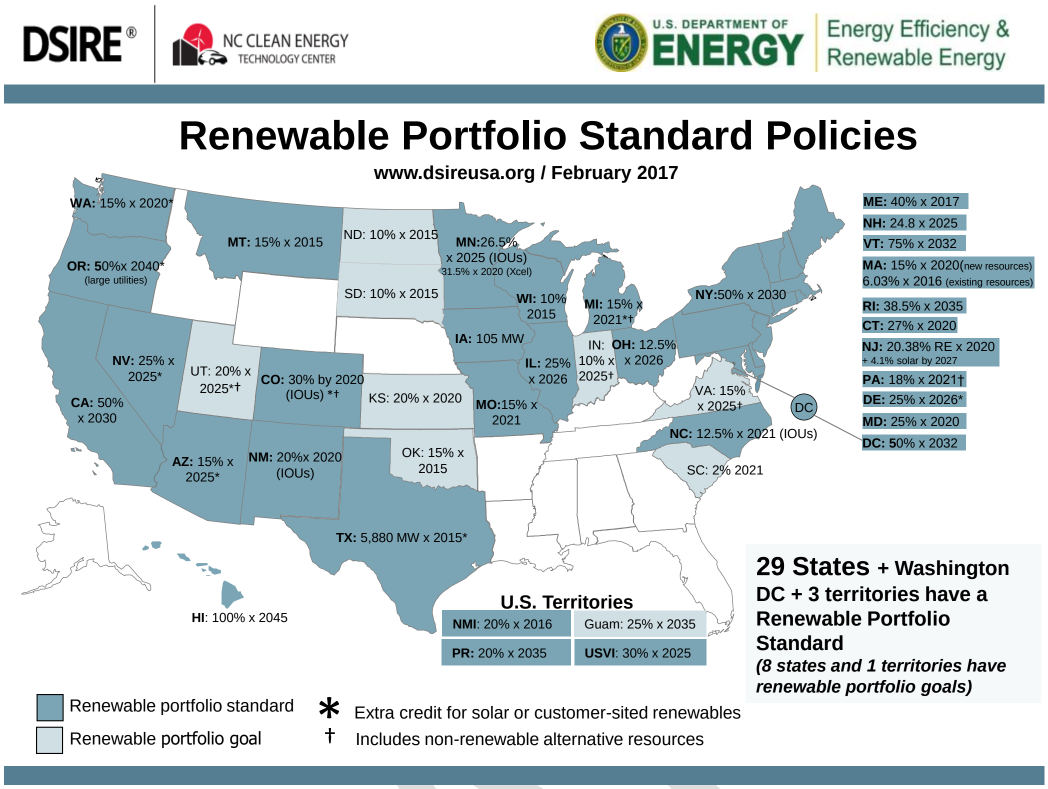


Figure 4.2-4: States and territories with Renewable Portfolio Standards

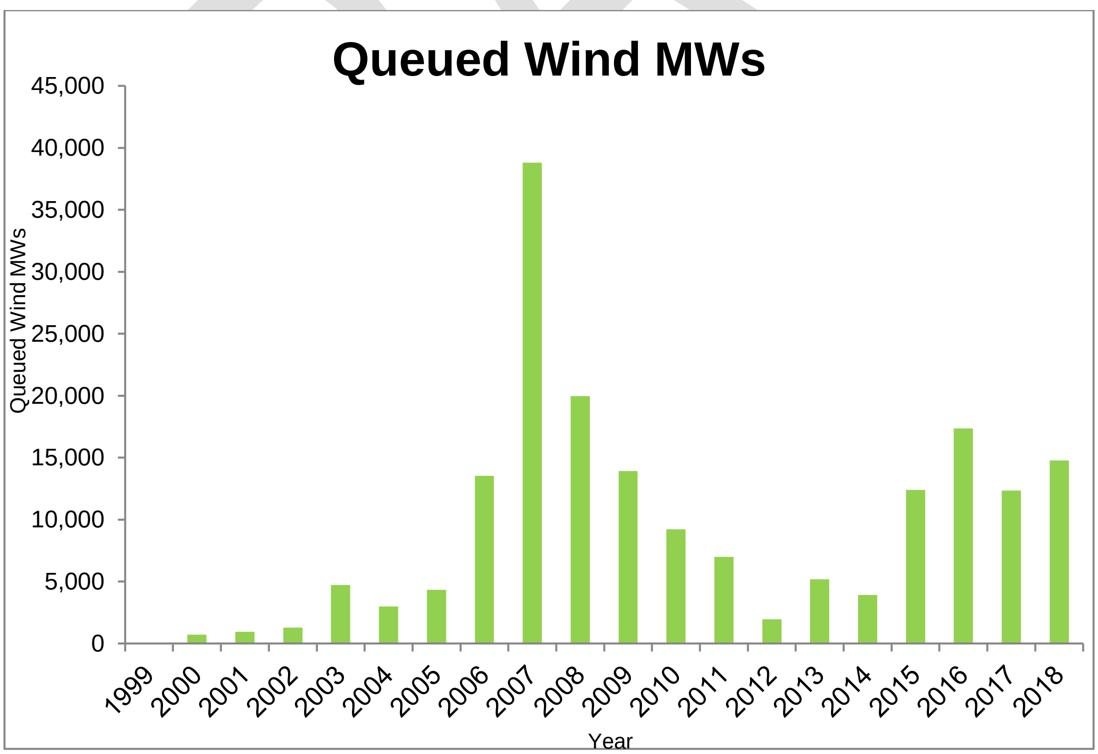


Figure 4.2-5: Wind – queued interconnection requests

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 and then a substantial drop (Table 4.2-3).

Year	Queued CT & CCCT MW	% Of All New Requests
2012	4,509	63%
2013	3,835	30%
2014	9,424	58%
2015	9,076	35%
2016	4,472	12.6%
2017	6,882	21.8%
2018	2,906	4.6%

Table 4.2-3: Combustion turbine (CT) and combined cycle combustion turbine (CCCT) – queued interconnection requests

Furthermore, there are approximately 22.5 GW of solar generation interconnection requests in the definitive planning phase (DPP) as of April 2018 (Figure 4.2-6). This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic modules.

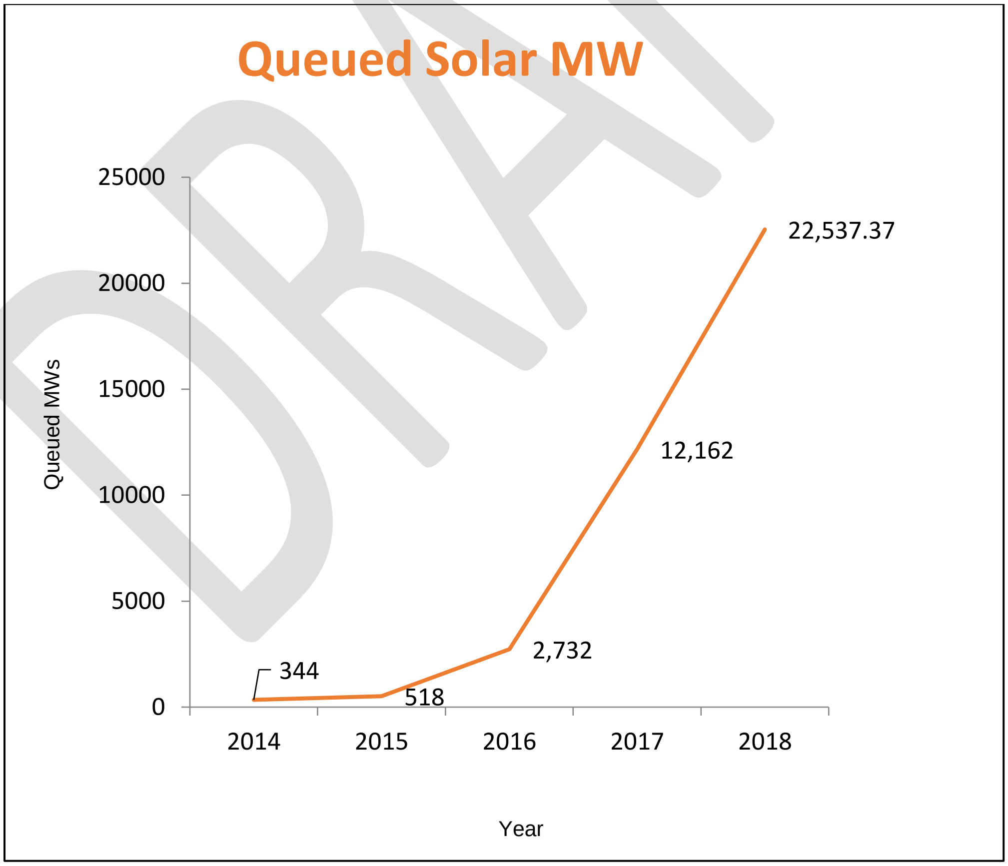


Figure 4.2-6: Solar – queued interconnection requests

Process Improvement

Over the past 13 years, the MISO Interconnection Process has evolved from a first-in, first-out methodology to first-ready, first-served methodology to move projects more efficiently through the generation project queue lifecycle.

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 values by MISO Tariff Administration.

From July 2017 to June 2018, MISO Transmission Service Planning processed 131 long-term TSRs (Figure 4.3-1) and completed 16 System Impact Studies for a total of 16 TSRs (Figure 4.3-1). Of these System Impact Studies, five TSRs were confirmed, three were refused/withdrawn, three executed a Facilities Study Agreement and five 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.

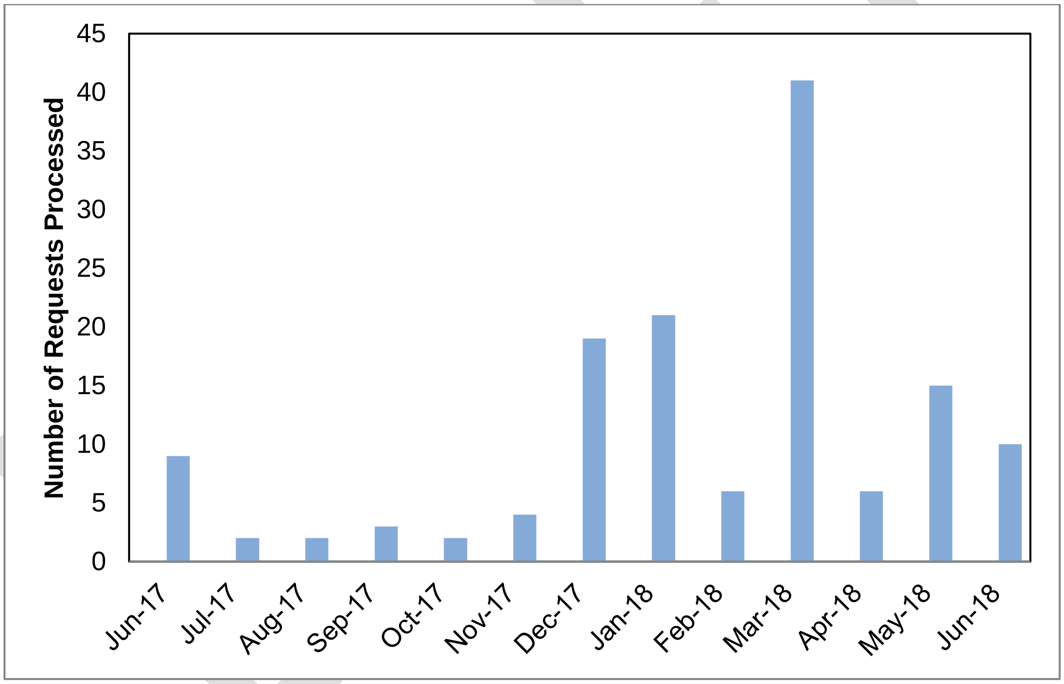


Figure 4.3-1: MISO Long-Term TSRs processed from July 2017 through June 2018

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. 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 Available Flowgate Capacity on the 15 most-limiting constrained facilities on a TSR path to verify adequate capacity. If the Available Flowgate Capacity is positive for all 15 constrained facilities, the request is likely to be approved. Negative Available Flowgate Capacity 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.

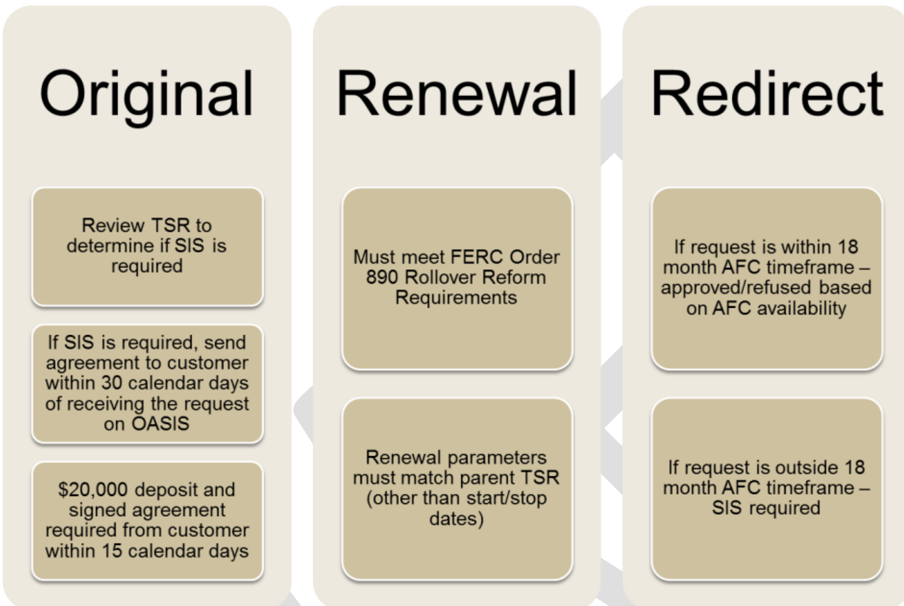


Figure 4.3-2: TSR triage phase processing

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, should they want 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.

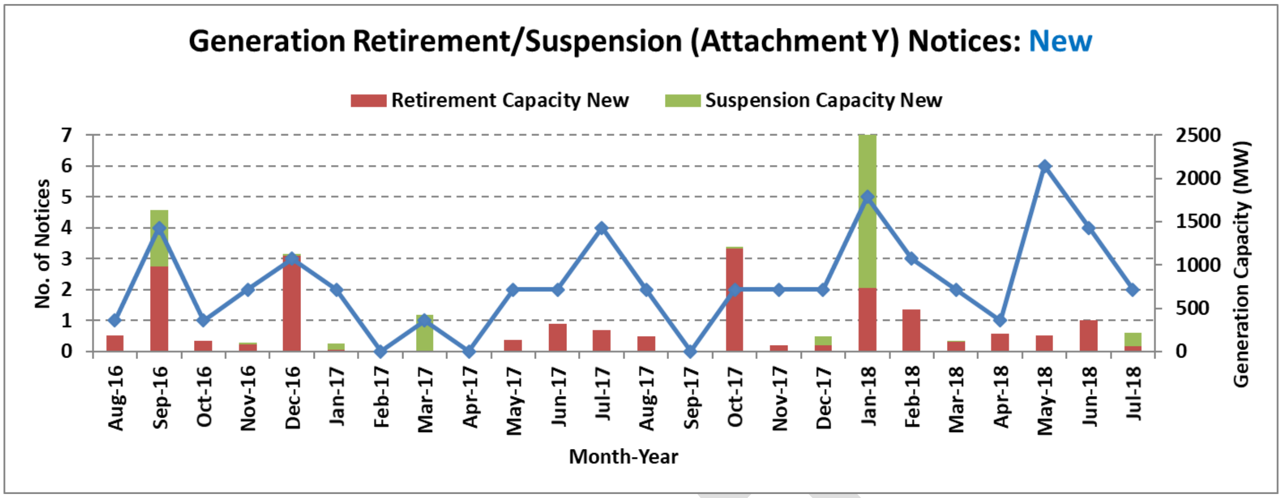
The MISO Attachment Y provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource

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 23 new Attachment Y Notices (4,371 MW) for unit retirement/suspension during the first seven months of 2018 (Figure 4.4-1). In the same period (January-July) in 2017 MISO received 11 Attachment Y retirement/suspension notices (1,219 MW) (Figure 4.4-1). MISO completed assessments and resolved a total of 14 Attachment Y Notices (3,249 MW) for unit retirement/suspension in the first seven months of 2018 (Figure 4.4-1).

The continuing evolution of the generation fleet and prevailing market economics continues to drive further retirements of uneconomic and less efficient resources.



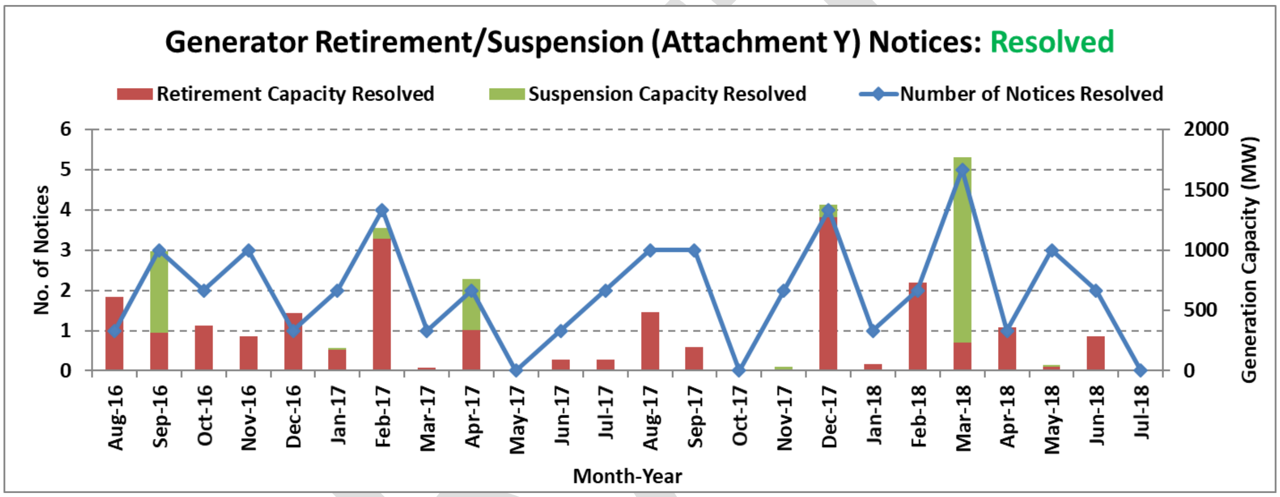


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 3,848 MW of generation capacity is retiring in 2018 and an additional 359 MW of generation capacity will retire in 2019 (Figure 4.4-2). This includes 2,680 MW of coal generation, 991 MW of gas generation and 177 MW of oil generation that is approved for retirement in 2018 and 359 MW of coal generation in 2019.

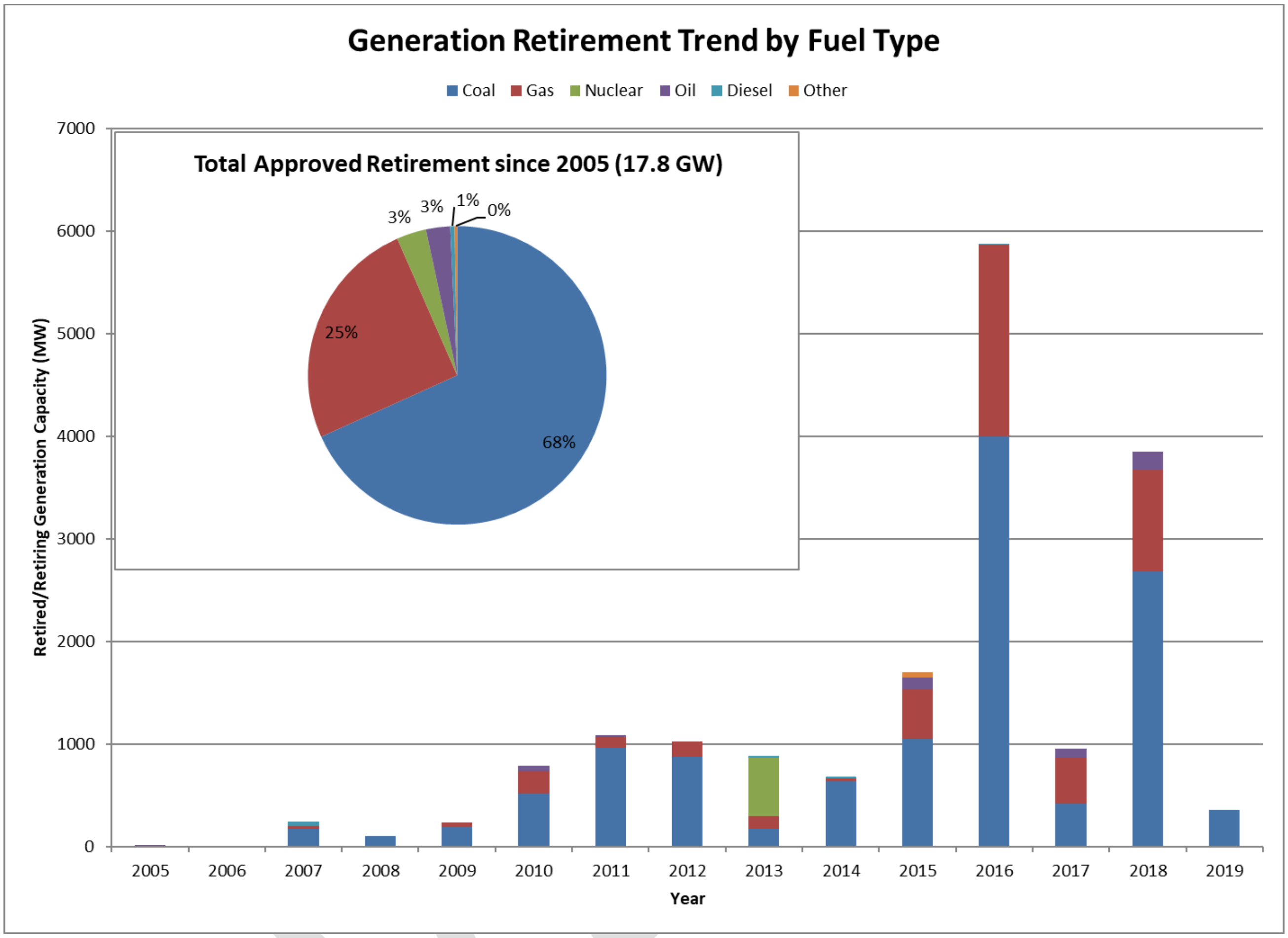


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2018 FERC Activity, Tariff Changes

Independent Market Monitor Recommendation

In May 2017, MISO filed changes to the Attachment Y Tariff provisions to address Independent Market Monitor (IMM) Recommendation 2013-14 related to the alignment of the Planning Resource Auction (PRA) and the Attachment Y process governing retirements and suspensions. The proposed Tariff changes remove barriers to participation in the PRA by providing more flexibility for resources to continue operation after MISO Approves the Attachment Y Notice based on the outcome of the Planning Resource Auction. All Attachment Y Notices will be initially submitted as suspension requests with limited opportunity to rescind within a three year-period. After the Attachment Y Notice has been approved the owner may defer a retirement decision until the results of the Planning Auction are determined.

MISO is awaiting a FERC Order on the filing.

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: Teche Unit 3 (Figure 4.4-3).

Teche 3 (335 MW) –The Cleco-Teche Unit 3 has been operating under an SSR agreement since April 1, 2017. MISO conducted an annual review of continued SSR need and determined that the unit is needed to continue operation as an SSR unit until the Terrebonne-Bayou Vista 230 kV Transmission Project is completed. MISO renewed the SSR Agreement for an additional 12-month term, which will end on April 1, 2019.

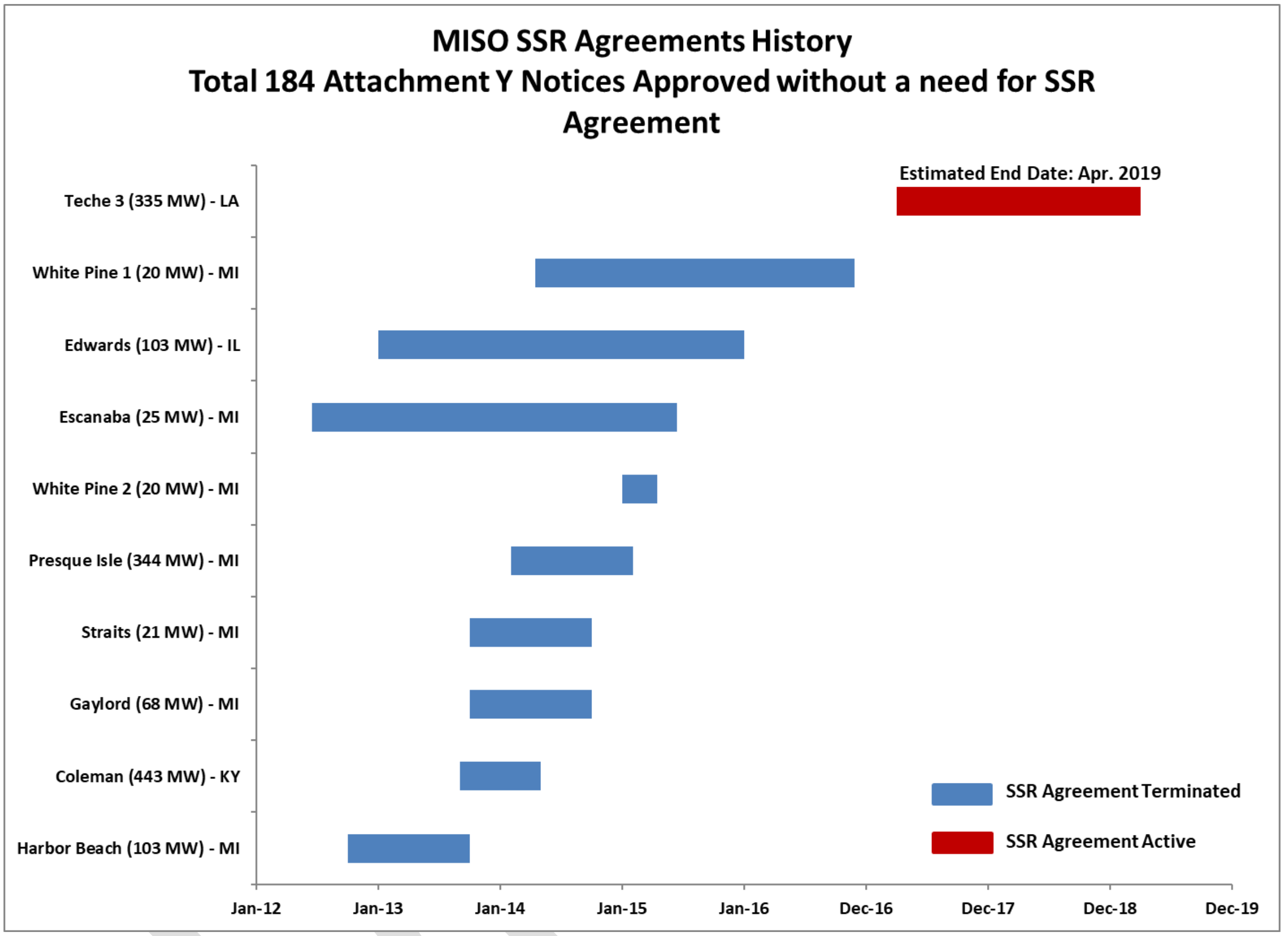


Figure 4.4-3: SSR history

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.

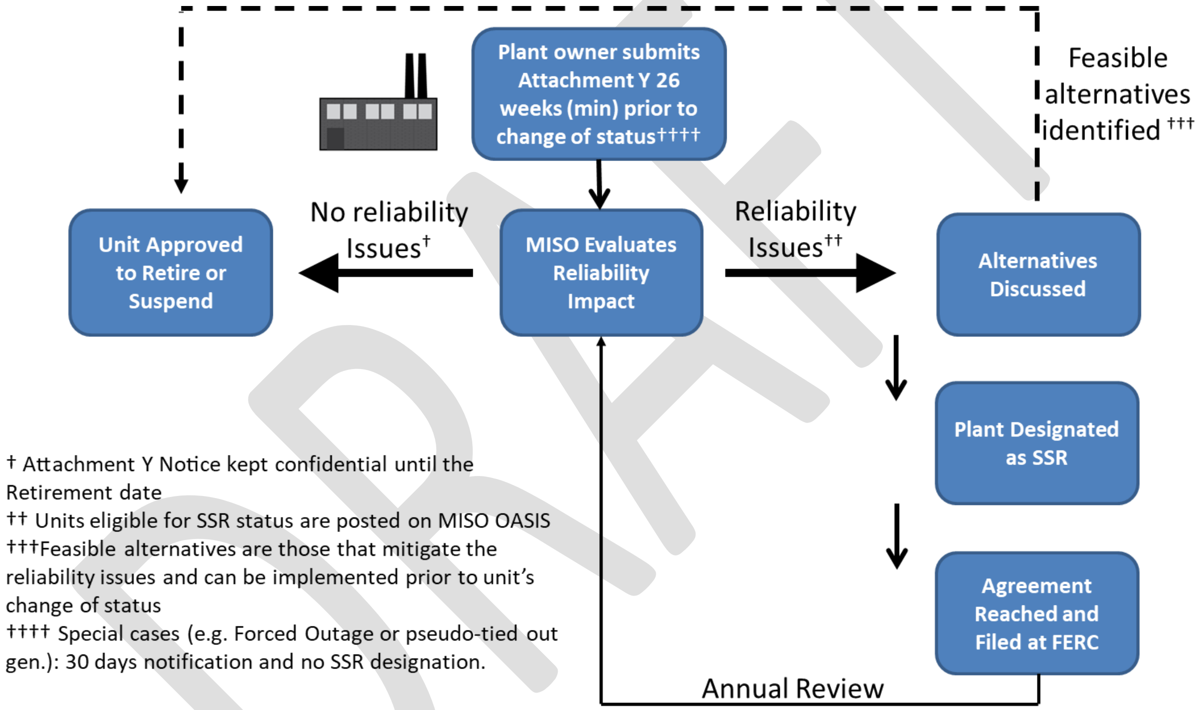


Figure 4.4-4: MISO Attachment Y process

4.5 Generation Deliverability Results

MISO performs generator deliverability analysis as a part of the MTEP18 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 three projects were identified to alleviate identified congestion

Analysis results revealed five constraints that restrict existing deliverable amounts in the MTEP18 near-term scenario (Table 4.5-1). Constraints observed that restrict generation beyond the established network resource amounts will be mitigated. MTEP projects have been identified for the mitigation required to alleviate the constraints identified within MISO; external constraints will be validated and the mitigation coordinated with the appropriate system.

Table 4.5-1 shows the preliminary list of constraints requiring mitigation. These constraints, and their associated mitigation, will be discussed throughout the MTEP19 study process.

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

Overloaded Branch	Area
Plaisance 138 kV – Champagne 138 kV	EES / CLECO
Addis 230 kV – Tiger 230 kV	EES
Tezcuco 230 kV – Frisco 230 kV	EES
Batesville 161 kV – Tallhache 161 kV	TVA
Batesville 161 kV – Batesville 161 kV	TVA

Table 4.5-1: MTEP18 Near-term Preliminary Constraints that Limit Deliverability

FERC Order 2003 mandates 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”[17] to be funded by the Interconnection Customer.

Constraints recognized as needing mitigation were identified in the 2023 scenario (Figure 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 MTEP18 2023 case. No new interconnection service is granted through the

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

annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

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

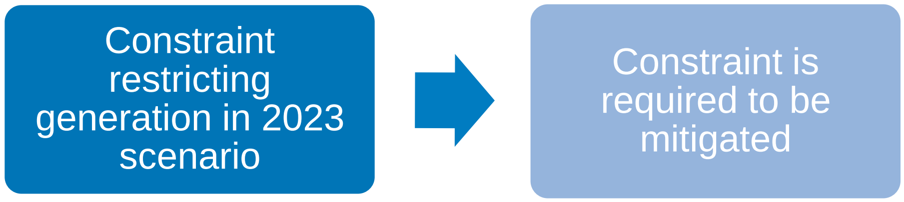
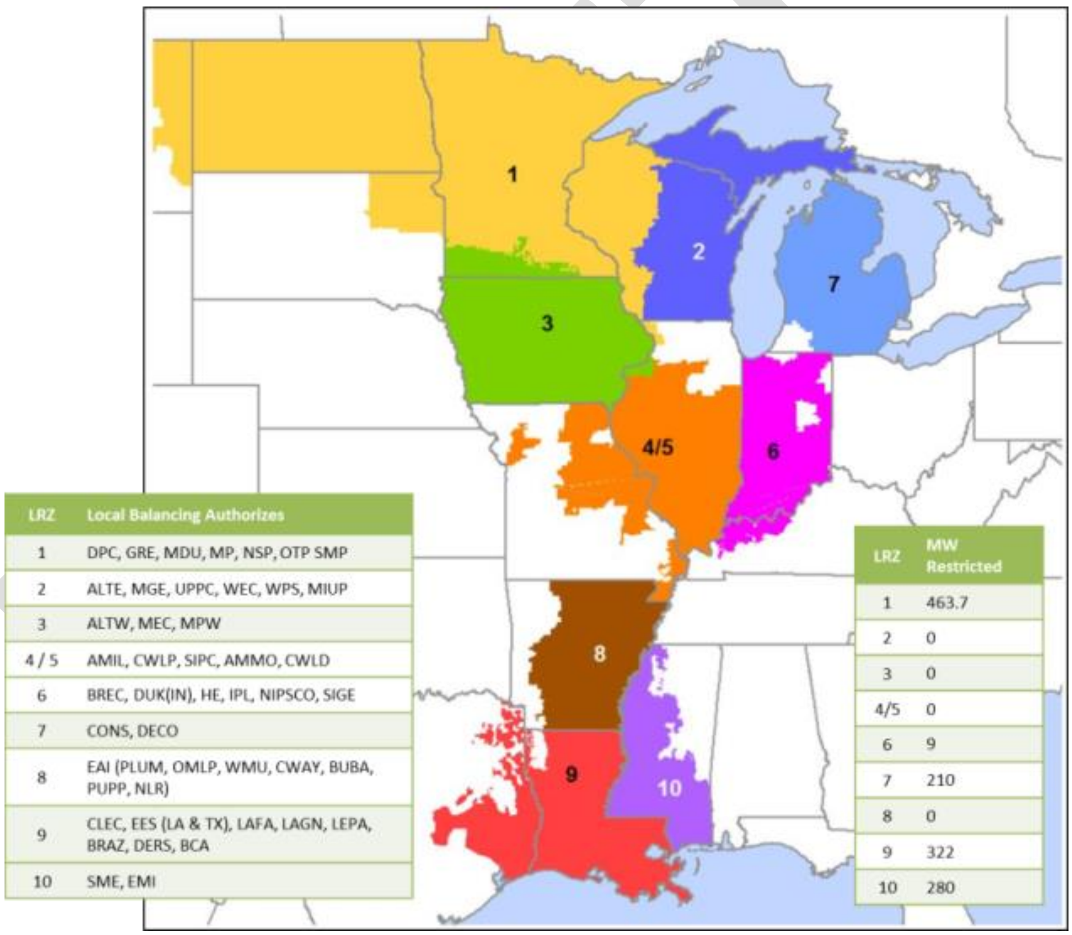


Figure 4.5-1: MTEP Deliverability Study Process Overview



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)

MTEP18 Mitigation

MTEP18 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 MTEP19 planning process and recommended for approval as appropriate. A mitigation stated as TBD already has verbal mitigation submitted with project submission pending. MISO will continue to evaluate and coordinate with Tennessee Valley Authority (TVA) to resolve the constraints seen on TVA's system.

Overloaded Branch	Area	Mitigation (MTEP ID)	Notes
Plaisance 138 kV – Champagne 138 kV	EES / CLECO	15584	Mitigated by Targeted Appendix A in MTEP19
Addis 230 kV – Tiger 230 kV	EES	15566 13894	Mitigated by Targeted Appendix A in MTEP19
Tezcuco 230 kV – Frisco 230 kV	EES	15605	Mitigated by Targeted Appendix B in MTEP19

Table 4.5-2: Preliminary projects to alleviate constraints that limit deliverability of network resources

MTEP17 Mitigation

MTEP17 near-term (five-year) summer peak deliverability analysis results showed four constraints that require mitigation. Mitigation was submitted for each of these constraints to alleviate limitation. Table 4.5-3 shows the projects provided for each of the four constraints requiring mitigation.

Overloaded Branch	Area	MW Restricted	Mitigation (MTEP ID)
Nashwauk 115 – 14L Tap 115 kV	MP	189.68	9646
Esso 230 – Delmont 230 kV	EES	16.47	9793
Star 115 kV – Mendenhall 115 kV	EES	116.47	13865
Lewis 138 kV – Sheawill 138 kV	EES	204.9	13864
Sheawill 138 kV – FW Pipe 138 kV	EES	8.12	13864
GRE Maple 69 kV – GRE Maple 69 kV	GRE	8.76	14145
Pere Marquette 138 kV – Lake County 138 kV	METC	1,157.9	13574

Table 4.5-3: MTEP17 projects submitted to alleviate constraints that limited deliverability of network resources during that cycle

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.

LTTRs are Auction Revenue Rights (ARR) allocated in the Stage 1A of the Annual ARR Allocation process. These LTTRs carry annual rollover rights lasting 10 years or more.

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 Auction Revenue Rights (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 the 2018-2019 planning year, the total LTTR payment is $387.5 million. The LTTR infeasibility uplift ratio is 2.93 percent (Table 4.6-1).

Region	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
MISO-wide	$440.6	$387.5	$13.0	2.93%

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 transmission rights over time.

Mitigations associated with limited LTTR feasibility are included where planned mitigation has been identified. in Table 4.6-2. Binding constraints are filtered for those with values greater than $200,000. 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 MTEP18 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2018	Fall 2018	Winter 2018	Spring 2019	Grand Total	Planned Mitigation
NSES - RAM452 161 FLO BLACKBERRY - NEOSHO 345	$252,145	$453,889	$259,777	$545,135	$1,510,946	N/A- Outside of MISO planning scope
GIBSON - PETERSBURG 345 FLO GIBSON - FRANCIS CREEK 345	$987	$727,536	$-	$26,415	$754,939	N/A
NASHUA T1_H 345/1 FLO NASHUA - HAWTHORN 345	$-	$234,736	$146,801	$223,077	$604,614	N/A- Outside of MISO planning scope
LONGMIRE - PONDER 138 FLO CONROE BULK - PONDER 138	$171,175	$314,655	$-	$-	$485,830	MTEP Project 12090 - Reconductor/rebuild to 1950A. ISD: 06/2021
WAPELLO TR92 161/69 FLO HILLS - MONTEZUMA 345	$224,718	$9,001	$107,201	$93,736	$434,657	N/A
STAUNTON - 08ALEN JUNCTION 138 FLO BLOOMINGTON E - BLOOMCIN H 230	$1,021	$326,693	$61,859	$22,781	$412,354	N/A
BOGALUSA AT3 500/230 FLO FRANKLIN - MCKNIGHT 500	$115,480	$-	$258,125	$29,235	$402,840	N/A
GRIMES - MT ZION 138 FLO HARTBURG - CYPRESS 500	$19,574	$129,400	$101,210	$94,314	$344,498	MTEP Project 10487 - Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor ISD 06/2020
MT ZION - LN485 138 FLO GRIMES - PONDER 230	$-	$-	$62,641	$221,709	$284,350	MTEP Project 10487 -- Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor ISD 06/2020

Constraint	Summer 2018	Fall 2018	Winter 2018	Spring 2019	Grand Total	Planned Mitigation
FRANKLIN - BOGALUSA 500 FLO FRANKLIN - MCKNIGHT 500	$-	$88,147	$-	$191,725	$279,872	N/A
ARK NU - PLEASANT HILL 500 FLO ARK NU - MABELVALE 500	$-	$155,786	$84,647	$-	$240,432	8041 Replace Terminal equipment to increase line rating ISD 04/2017
SHADELAND - LAFAYETTE 138 FLO 08NW TAP - W LAFAYETTE 138	-$7,358	$182,743	$2,826	$60,152	$238,361	N/A
MARBLEHEAD N 161/138 TR1 FLO MAYWOOD-HERLEMAN 345	$56,311	$67,579	$56,657	$56,546	$237,092	N/A
BATESVILL - HUBBLE 138 FLO TRIMBLE COUNTY - CLIFFY CREEK 345	$-	$218,794	$-	$-	$218,794	N/A
GRIMES - MT ZION 138 FLO GRIMES AT4 345/230	$214,178	$-	$-	$-	$214,178	MTEP Project 10487: Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor
GRIMES - MT ZION 138 FLO GRIMES - BENTWATER 138	$-	$153,135	$58,097	$-	$211,232	MTEP Project 10487: Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor

Table 4.6-2: Infeasible Uplift Breakdown by Binding Constraints from the 2018 Annual FTR Auction

Section 5: Economic Analysis

5.1 Economic Analysis Introduction

The MISO Value-Based Planning Process endeavors to develop transmission expansion plans that minimize total electric costs; maintain an efficient market; and enable state and federal public energy policy — all while maintaining adequate system reliability.

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.

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

MISO previously performed a generator outlet study that provided extensive information for determining an optimal balancing point between transmission investment and generation production costs. The study 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. Similarly, it was 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 MISO Value-Based planning approach incorporates multiple perspectives by conducting reliability and economic analyses (Figure 5.1-1).

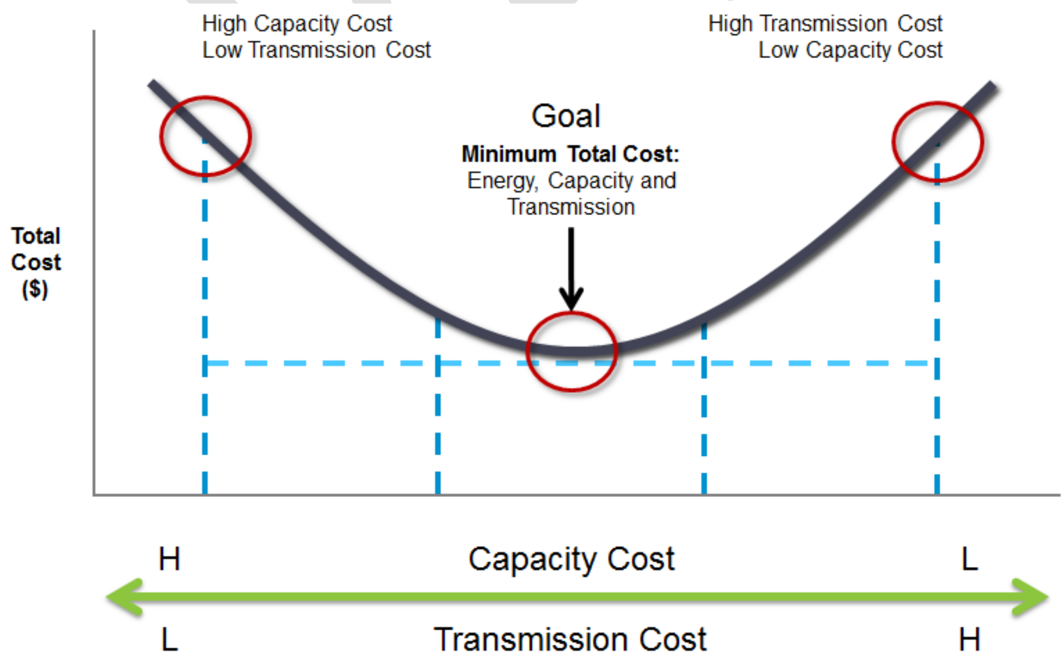


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

Since MTEP06, the MISO planning process has used multiple future scenarios to model out-year policy and 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 planning vetted hierarchy. MISO regional resource forecasts include the 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 continuous 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 towards 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, POM, TSAT 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.

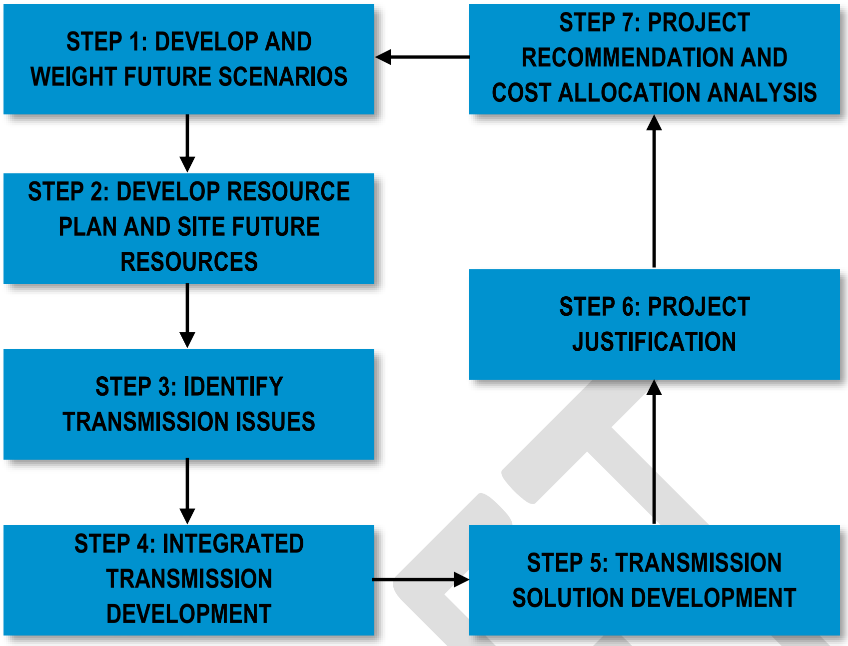


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

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 provide 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 MTEP18 future scenarios is in Section 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 MTEP18 future is in Section 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. This data can be used to inform the value-based planning process both at a high 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 the 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 any 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 still perform well through this phase then undergo contingency screening to identify any new flowgates that may be needed because of the project. Any new flowgates that are identified will be added to the project's event files and a full present value analysis will be conducted again to see how much of an impact the new flowgates 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. 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 that evaluate the impact certain future assumptions may have on a project. These sensitivities help to ensure that the projects that 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 meet or exceed all criteria for the type of project recommended. Projects meeting or exceeding all project type criteria will be recommended to the MISO Board of Directors in the last quarter of each MTEP cycle, or as otherwise defined in the MISO Tariff.

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

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

Table 5.1-1: Summary of MISO Cost Allocation mechanisms

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

- Identification and selection of transmission issues through a multifaceted needs assessment up front, 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 MTEP18, MISO's Value-Based Planning Process is exemplified in the MTEP Future Development (Section 5.2), and Market Congestion Planning Study (Section 5.3).

5.2 MTEP Futures Development

MTEP future scenario-based analysis provides the basis for developing robust, reliable, value creating transmission plans. MTEP futures are a stakeholder-driven postulate of what the industry landscape could be in the 10-20 year planning horizon. With the increasingly interconnected nature of utilities, electric industry organizations, and state and federal interests, forecasting a range of plausible futures greatly enhances the robustness of the planning process for electric infrastructure. The futures development process provides information on the bulk-electric-system impacts of varying load growth, environmental legislation, fuel-price variability, renewable development, demand-side management programs, energy storage, legislative decisions and many other potential scenarios.

The goal of the MTEP futures is to bookend uncertainty by defining a wide range of potential plausible outcomes. Futures are intended to be long-term and consider not only outcomes that could come to be within the next five years, but also plan for uncertainty that could affect our industry through the next 15 years. To accomplish this goal, MISO, in coordination with stakeholders, updated the three previous MTEP17 Futures while adding a fourth Distributed and Emerging Technologies future, to consider emerging technology trends (Table 5.2-1).

MTEP18 Future	Limited Fleet Change	Continued Fleet Change	Accelerated Fleet Change	Distributed & Emerging Technologies
Demand and Energy	Low (10/90) High LRZ9 Industrial	Base (50/50)	High (90/10) Low LRZ9 Industrial	Base + EV *Energy: 1.1%* *Demand: 0.6%*
Fuel Prices	Gas: Base -30% Coal: Base -3%	Base	Gas: Base +30% Coal: Base	Base
Demand Side Additions *By Year 2032*	EE: - GW DR: 2 GW	EE: - GW DR: 3 GW	EE: 5 GW DR: 4 GW	EE: 2 GW DR: 3 GW Storage: 2 GW
Renewable Additions *By Year 2032* *(% Wind and Solar Energy)*	10%	15%	30%	20%
Generation Retirements[1] *By Year 2032*	Coal: 9 GW Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW	Coal: 17 GW+ Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW Nuclear: 2 GW
CO_2 Reduction Constraint *From Current Levels by 2032*	None	None	20%	None
Siting Methodology[2]	MTEP Standard	MTEP Standard	MTEP Standard	"Localized"

EV: Electric Vehicles EE: Energy Efficiency DR: Demand Response

1. In Accelerated Fleet Change Scenario 17 GW of coal retired instead of the 24 GW in the MTEP17 Accelerated Alternative Technologies Future. Instead of additional retirements, must-run was removed and coal units run only seasonally five years before their retirement date.
2. "Localized" renewable siting assumes that at least 50 percent of incremental wind and solar energy will be sourced within each Local Resource Zone. Two-thirds of solar sited as distributed.

Table 5.2-1: MTEP18 Key Attributes

Futures Narratives

Limited Fleet Change (LFC)

Existing generation fleet remains relatively static without significant drivers of change. Some coal fleet reductions are expected as units reach the end of their useful life. Renewable additions are driven solely by current Renewable Portfolio Standards under low demand and energy growth rates.

- Footprint wide, demand and energy growth rates are low; however, as a result of low natural gas prices, industrial load along the Gulf Coast increases.
- Natural gas prices are low due to increased well productivity and supply chain efficiencies along with low demand and energy growth.
- Low demand and energy and natural gas prices reduce the demand for and economic viability of new generation technologies.
- Thermal generation retirements are driven by unit useful life limits. Nuclear units are assumed to have license renewals granted and remain online.
- Lower levels of demand-side management programs are assumed due to low demand and energy growth.

Continued Fleet Change (CFC)

The fleet evolution trends of the past decade continue. Coal retirements reflect historical retirement levels based on average age of retirement. Renewable additions continue to exceed current Renewable Portfolio Standard Requirements as a result of economics, public appeal, and the potential for future policy changes. Natural gas reliance increases as a result of new capacity needed to replace retired coal capacity.

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 Module E forecast.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Renewable additions continue along current trends. Wind and solar serve 15 percent of MISO energy by 2032.
- Maturity cost curves for renewable resources reflect some advancement in technology and supply chain efficiencies.
- Oil and gas generators retired at the useful life limit age. Coal units will be retired reflecting age and historical retirements in advance of age limits. Nuclear units are assumed to have license renewals granted and remain online.
- Demand-side management programs modeled to reflect growth and technical potential of current programs.

Accelerated Fleet Change (AFC)

A robust economy with increased demand and energy drives higher natural gas prices. Carbon regulations targeting a 20 percent reduction from current levels are enacted in response to increased demand and energy driving coal to decrease production. Increased renewable additions are driven beyond renewable portfolio standards by need for new generation, technological advancement, and carbon regulation. Natural gas reliance increases as a result of new capacity needs driven by the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand and energy grows at a high rate due to a robust economy; however, as a result of high natural gas prices, industrial load along the Gulf Coast decreases.
- Natural gas prices are high due to increased demand.

- Thermal retirements, economics, and potential regulations drive renewable additions. Maturity cost curves for renewable technologies applied reflecting greater technological advancement.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and historical retirements in advance of age limits. Nuclear units are assumed to have license renewals granted and remain online.
- A 20 percent carbon reduction for current levels is modeled to reflect future national or state-level carbon regulation.
- High demand and energy levels and carbon regulation drive greater potential for demand-side management programs.

Distributed and Emerging Technologies (DET)

Fleet evolution trends continue, primarily driven by local policies and emerging technology adoption. State level policies reflect desires for local reliability and optionality. Coal retirements reflect historical retirement levels based on average age of retirement. Increased renewable additions are driven by favorable economics resulting from technological advancements and state-level renewable portfolio standards and goals with targeted increases in distributed solar. Natural gas reliance increases as a result of new capacity needs driven by load growth largely driven by electric vehicles, the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand and energy forecast begins with level equivalent to a 50/50 Module E forecast and has high growth rate to reflect adoption of electric vehicle technology on a broader scale. Energy grows faster than demand reflecting smart-charging of electric vehicles.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Maturity cost curves for renewable technologies applied reflecting advancement in technologies and supply-chain efficiencies. Renewable additions reach about 20 percent of MISO energy by 2032; increase from 15 percent in Continued Fleet Change Future driven primarily by solar.
- Increased deployment of energy storage devices driven by economies of scale resulting from commercial mass production of lithium ion batteries and other viable technologies.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and economics. Nuclear units are assumed to retire at license expiration dates.
- Demand-side management programs modeled to reflect growth and technical potential of current programs.

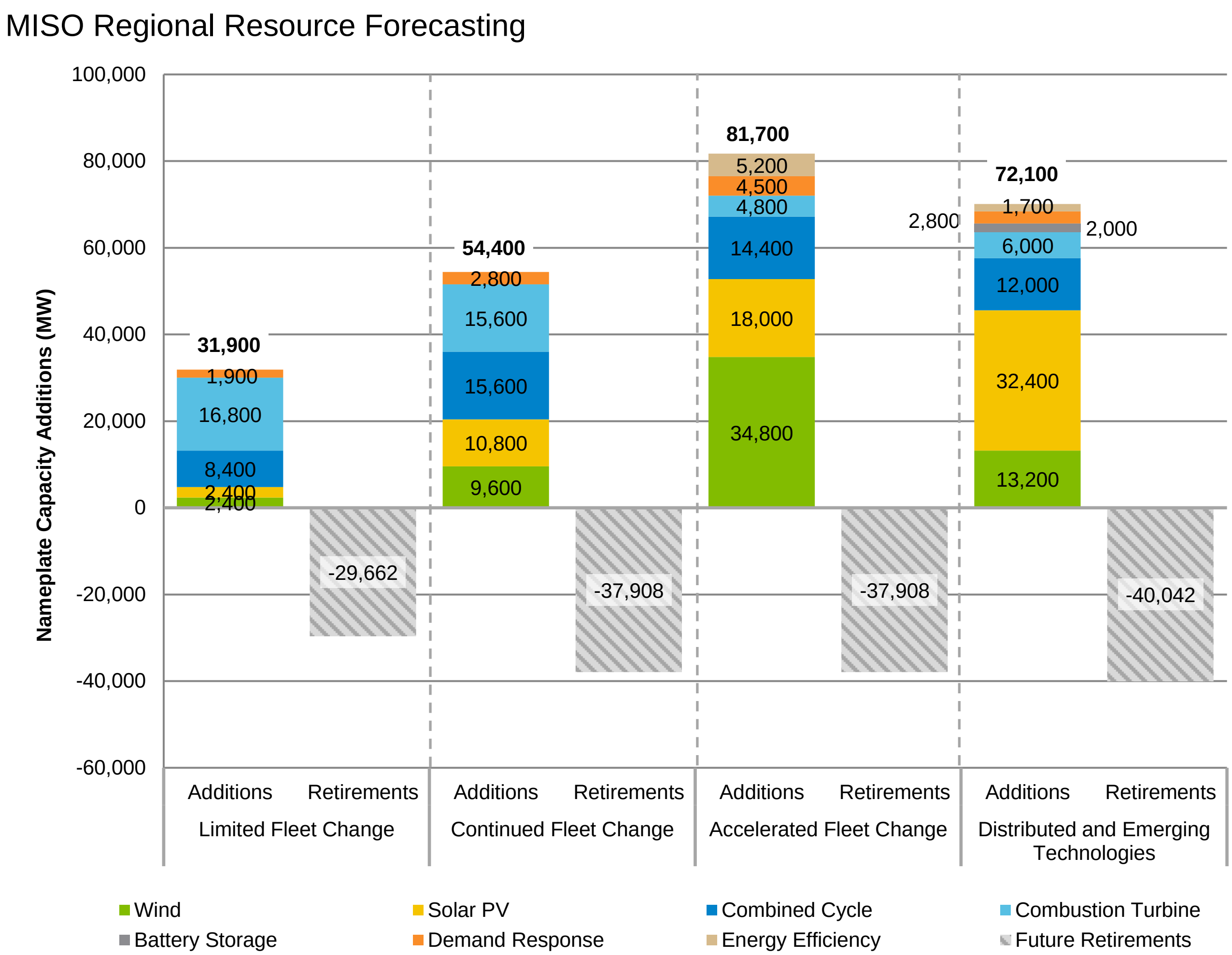


Figure 5.2-1: Forecasted MISO Capacity Expansion under the MTEP18 Futures (2017 – 2032)

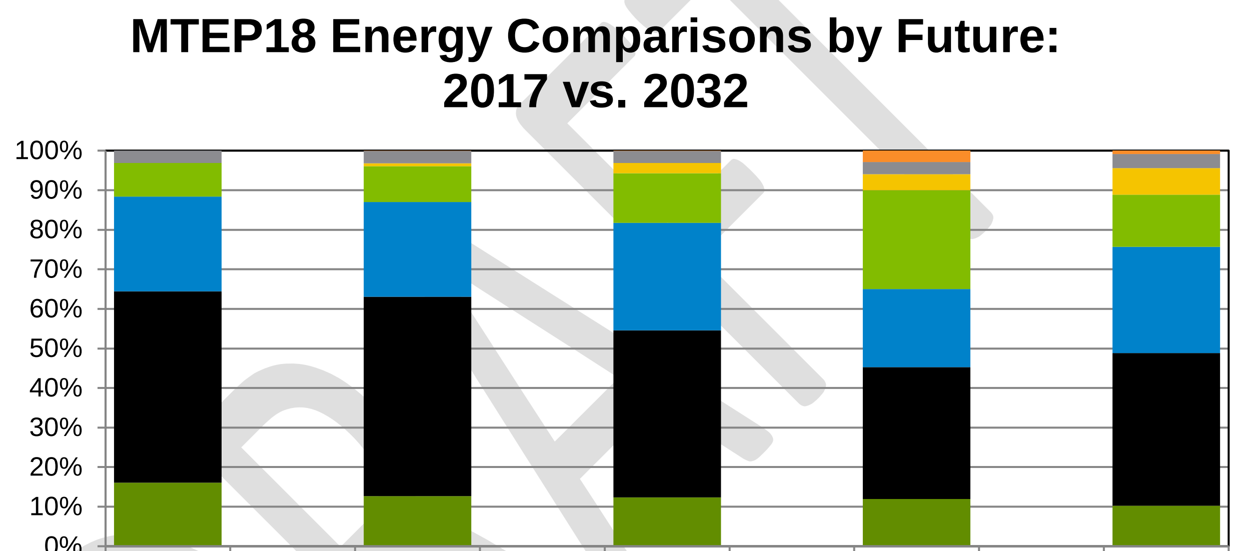
MTEP18 futures result in various levels of resource additions and retirements displayed in Figure 5.2-1. Results are reflective of the retirement, load-growth, renewable levels and emissions constraints applied.

Limited Fleet Change resources added are a direct result of the lower demand and energy growth assumption and lower assumed age-related retirements. Renewables are only added to meet RPS requirements, achieving 10 percent wind and solar energy. Selection of combustion turbines over combined cycles reflects a lower gas price and the need for more peaking capacity rather than energy-providing baseload units.

Continued Fleet Change experiences a balanced buildout of gas units and renewables to reflect fleet progression based on historical trends. Wind generation has lower initial cost, selected initially to meet the RPS requirement while solar generation cost declines make it the more favorable selection in later years. Both solar and wind cost trends from the National Renewable Energy Laboratory's Annual Technology Baseline forecasts.

The Distributed and Emerging Technologies future renewables level was set to 20 percent energy highlighting the adoption of more distributed technologies, mainly solar, in a system with high energy growth from electric vehicle deployment. In this scenario the cost of solar matures more quickly due to faster penetration and adoption of solar technology. Battery storage is also projected within the Distributed and Emerging Technologies future.

Accelerated Fleet Change experiences the greatest increase in renewable additions driven by a 20 percent carbon dioxide reduction from current levels along with more aggressive renewable cost maturity curves. Combined with an increased level of coal retirements and load growth, this scenario achieves 30 percent renewable energy by 2032. Twice as much renewable capacity is required to replace the retired thermal capacity and meet future demand due to the low capacity credits of wind and solar.



	2017 Historical	LFC 2032	CFC 2032	AFC 2032	DET 2032
DSM	0%	0%	0%	3%	1%
Other	3%	3%	3%	3%	3%
Solar	0%	1%	3%	4%	7%
Wind	9%	9%	13%	25%	13%
Gas	24%	24%	27%	20%	27%
Coal	48%	50%	42%	33%	39%
Nuclear	16%	13%	12%	12%	10%

Figure 5.2-2: MTEP18 Futures Energy by Future (2017 vs. 2032)

Figure 5.2-3 shows the energy utilization of the system in year 2017 actuals compared to the forecasts for year 2032 for each of the MTEP18 futures. It can be seen that futures energy consumption trends track with the input assumptions of the respective futures. So LFC with lower renewable energy requirements, coal retirements and lower growth means longer reliance on coal energy because of less fleet change.

Going up from there, reliance shifts to more gas and renewables as retirements, load growth, and renewable requirements or carbon dioxide constraints impact fleet dispatch.

MTEP18 Futures	Gross Growth Rates		Net Growth Rates	
	Demand	Energy	Demand	Energy
Limited Fleet Change	0.3%	0.3%	0.3%	0.3%
Continued Fleet Change	0.5%	0.5%	0.5%	0.5%
Accelerated Fleet Change	0.7%	0.7%	0.4%	0.5%
Distributed and Emerging Technologies	0.6%	1.1%	0.5%	1.0%

Table 5.2-2: Gross and Net Demand and Energy Growth Rates

Table 5.2-2 compares the gross and net demand and energy growth rates by future. Net demand growth rates are a result of the selected energy efficiency programs provided by Applied Energy Group (AEG). Because the base Module E forecasts are apparently net of older, well-established energy efficiency (EE) programs, it was assumed that not all low-cost AEG developed EE programs were available, and so were reduced to not double EE inherent in the forecasts.

Capacity Siting

Generation resources forecasted from EGEAS[18] are specified by fuel type and timing, but these resources are not site specific. The process requires a siting methodology tying each resource to specific buses in the power flow model and represented using the MapInfo Professional Geographical Information System (GIS) software.

MISO's capacity siting, the process used to predict likely locations where future generators will be built, is differentiated by fuel type i.e. the process is tailored differently to site thermal natural gas units and renewable units. The siting process generally utilizes a priority based approach which first identifies sites using the MISO Generator Interconnection Queue, and looks at existing site expansion or replacement, and finally explores greenfield sites. More detailed siting guidelines, methodologies and the results for the other futures are depicted in Appendix E-2 (Figures 5.2-3 through 5.2-6).

[18] Electric Generation Expansion Analysis System: a forecasting tool that uses the future-specific variables to predict economic future generation needs

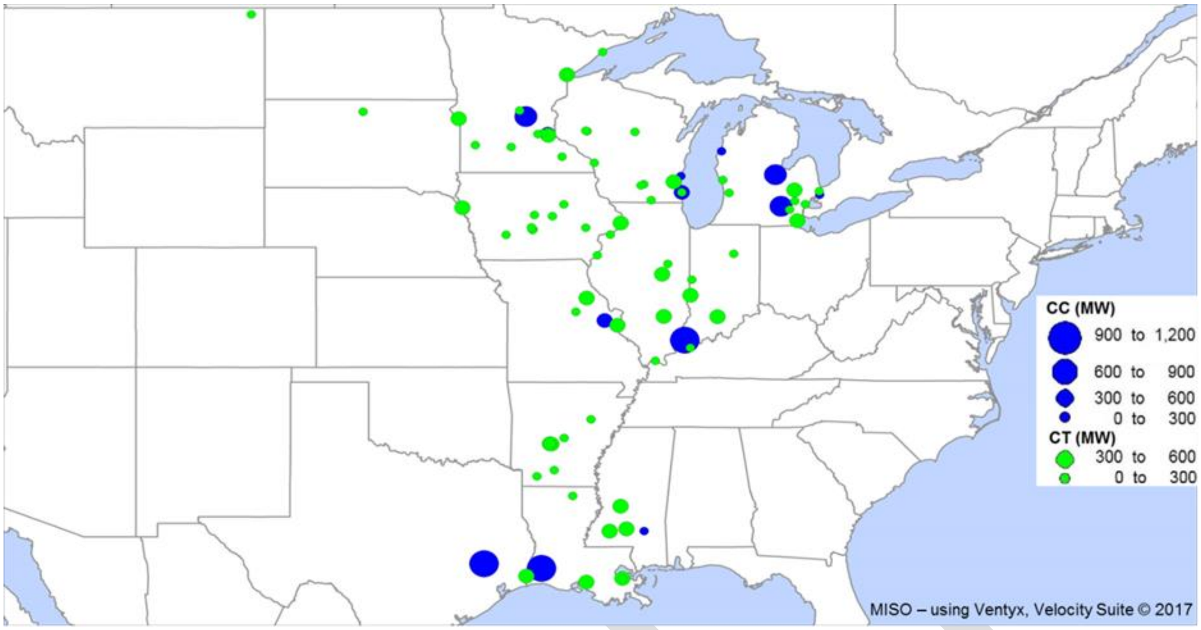


Figure 5.2-3: Limited Fleet Change Thermal Generation Additions Siting Map

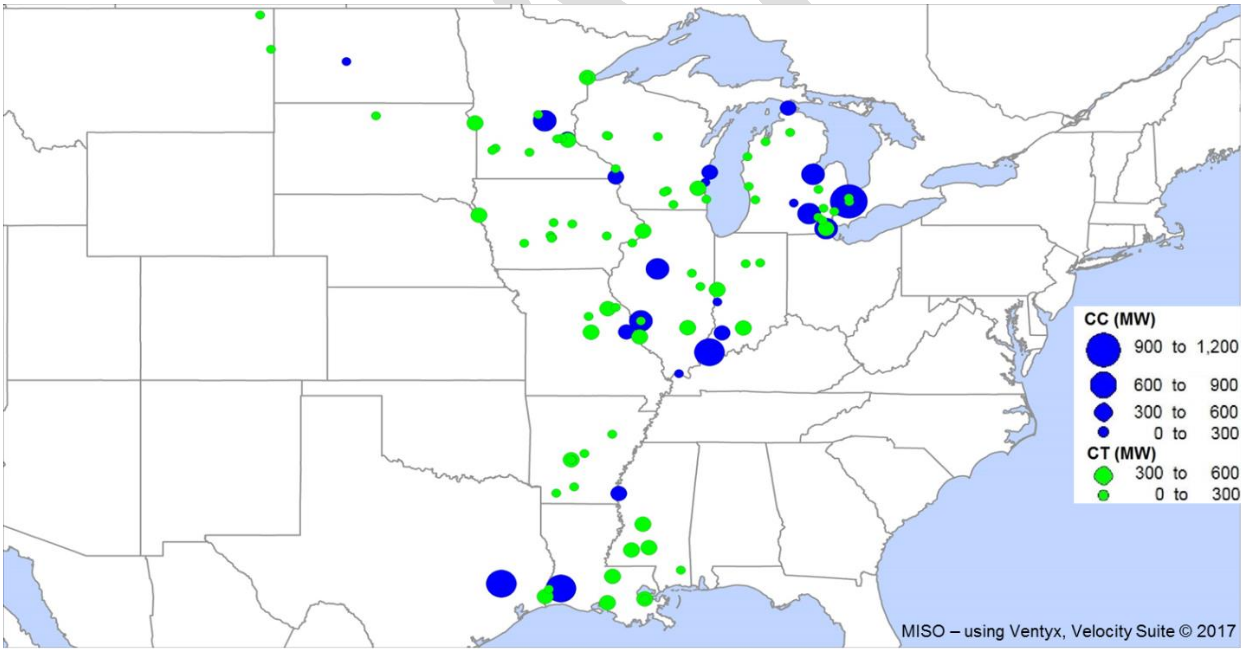


Figure 5.2-4: Continued Fleet Change Future Thermal Generation Additions Siting Map

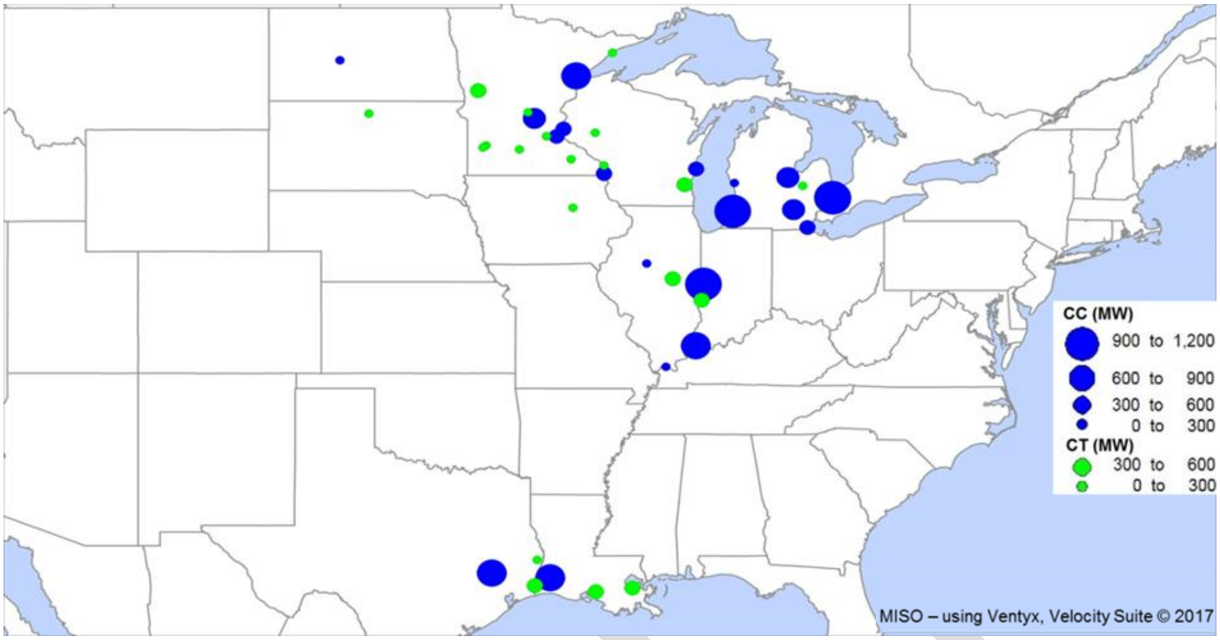


Figure 5.2-5: Accelerated Fleet Change Future Thermal Generation Additions Siting Map

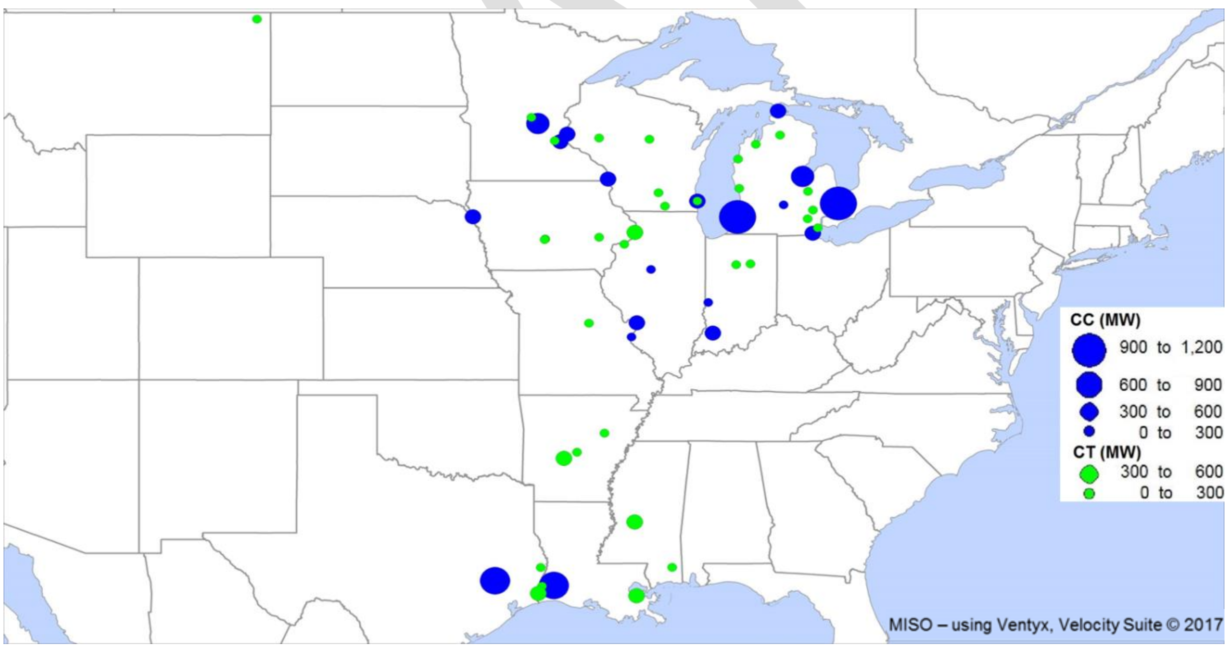


Figure 5.2-6: Distributed and Emerging Technologies Future Thermal Generation Additions Siting Map

5.3 Market Congestion Planning Study

The Market Congestion Planning Study (MCPS) develops 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 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.

A consolidated economic planning effort has been undertaken for the MISO North/Central and South regions in MTEP18 in order to better align the study process across the MISO footprint.

Study Summary: MCPS North/Central Region

In the MISO North/Central MCPS, a total of 13 top congested flowgates in five focus areas were identified based on the level of congestion. The five focus areas are: Dakotas/Minnesota, Wisconsin, Iowa, Northern Indiana and Southern Indiana/Kentucky.

MISO staff and stakeholders collaborated on the development of transmission solutions to mitigate congestion in the five focus areas. Each solution was tested for its robustness to address system needs under a wide variety of scenarios, embodied by the MTEP18 futures. A total of 68 transmission solutions were proposed and studied. Four project candidates were established for further analysis to ensure both economic needs will be met and will not degrade reliability. Of the four project candidates, three were selected as best-fit projects with a weighted benefit-to-cost ratio above 1.25 to both MISO and local Transmission Pricing Zone (TPZ). These three best-fit projects relieved primary flowgate congestion, passed reliability no-harm test and showed robust economic benefits under multiple scenarios evaluated. None of the projects meet the voltage threshold to be eligible as Market Efficiency Project (MEP). Consequently, the three projects below will be included in MTEP18 as Economic Other projects for Board of Director approval.

- Rebuilding the existing Wabaco to Rochester 161 kV with an estimated cost of $11 million.
- Adding series reactor on Forest Junction to Elkhart Lake 138kV with an estimated cost of $2 million.
- New Wilson to BR Tap 161 kV line, re-conductoring BR Tap to Paradise 161 kV, upgrading terminal equipment at Matanzas and removing switch at BR Tap with an estimated cost of $16 million.

Study Summary: MCPS South Region

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 2018 MCPS study effort for the South region is built on the progress made during previous MTEP cycles, which identified several congested flowgates and evaluated the applicable transmission solutions. The 2018 cycle focuses on four specific areas in MISO South: Arkansas, Louisiana, Texas and Mississippi.

In the MTEP18 MCPS study effort, transmission solutions were designed in a collaborative effort between MISO and stakeholders. Each solution was tested for robustness to address system needs under a variety of scenarios, embodied by the MTEP18 futures. None of the solutions analyzed for the South region met the requirements for economic project benefits. However, a single Baseline Reliability Project is being recommended to address both reliability and economic needs in the Natchez focus area.

MCPS Study and Process Overview

The MCPS begins with a bifurcated Flowgate 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 MTEP18 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 defined, the study evaluates multiple transmission alternatives in an iterative fashion with both economic and reliability considerations. The Project Candidate Identification phase includes: screening analysis to identify 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.

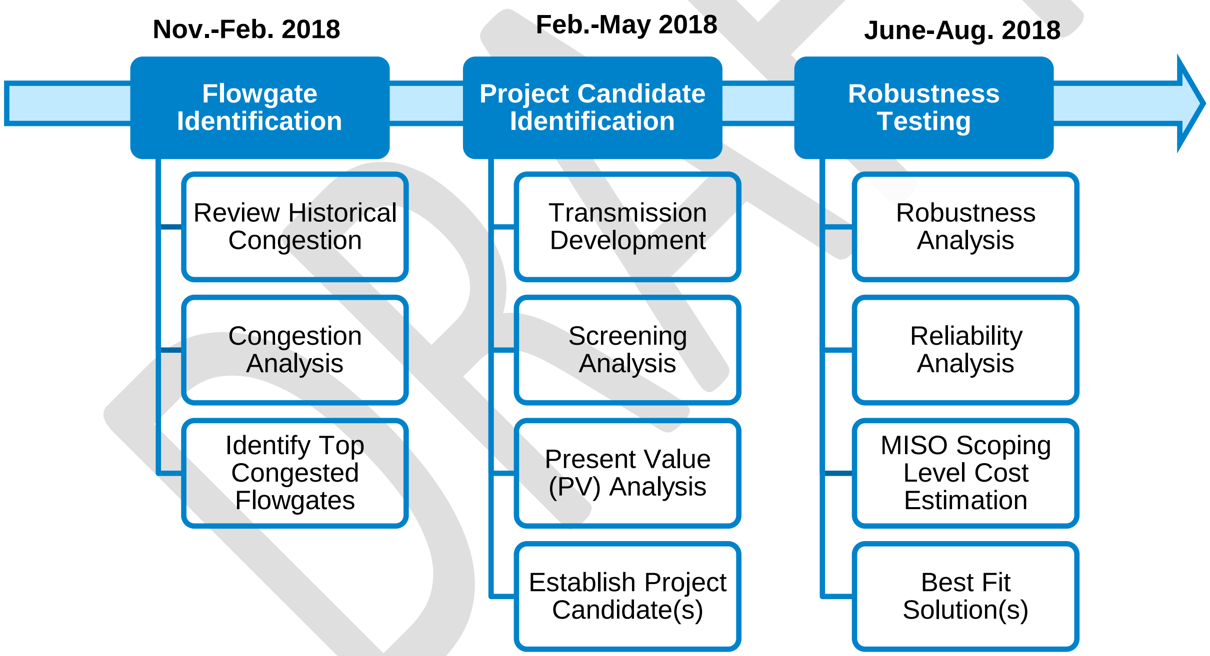


Figure 5.3-1: MCPS Process Overview

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 future scenarios -– Limited Fleet Change (LFC), Continued Fleet Change (CFC), Accelerated Fleet Change (AFC) and Distributed and Emerging Technologies (DET) -– each have a future weight for the MTEP18 MCPS study (Table 5.3-1)

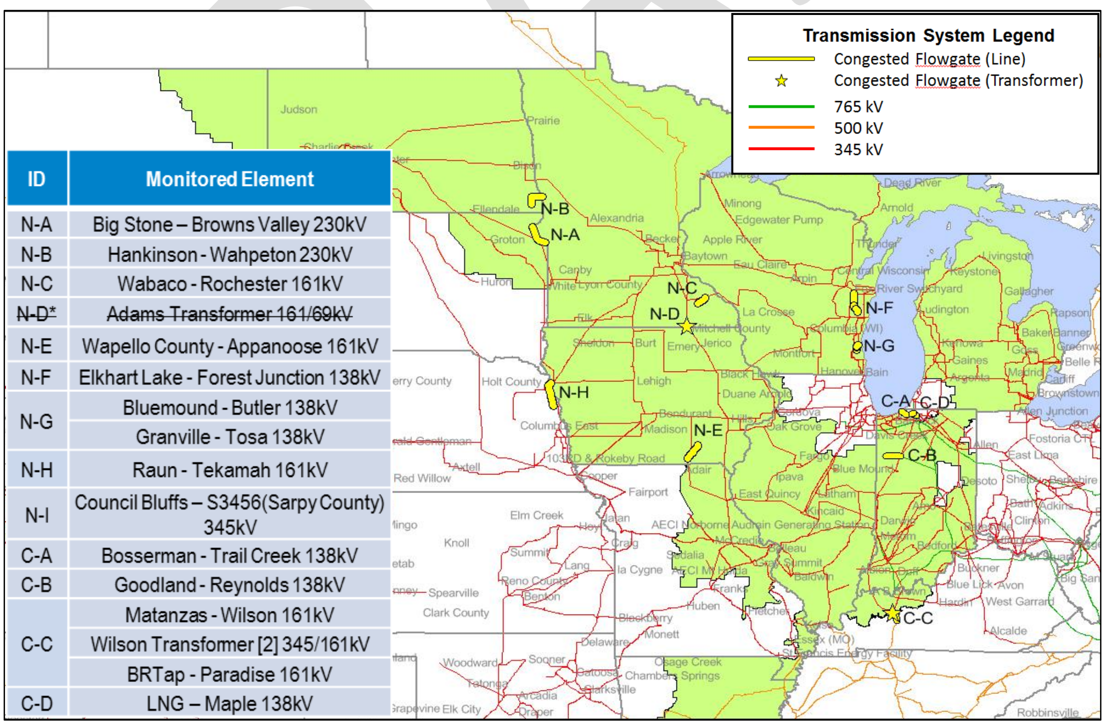
MTEP18 Future	Future Weight (%)
Limited Fleet Change (LFC)	25
Continued Fleet Change (CFC)	30
Accelerated Fleet Change (AFC)	20
Distributed and Emerging Technologies (DET)	25

Table 5.3-1: MTEP18 MCPS Future Weights

MISO assigns weights to each future considering input from the Planning Advisory Committee (see Section 5.2, MTEP Future Development).

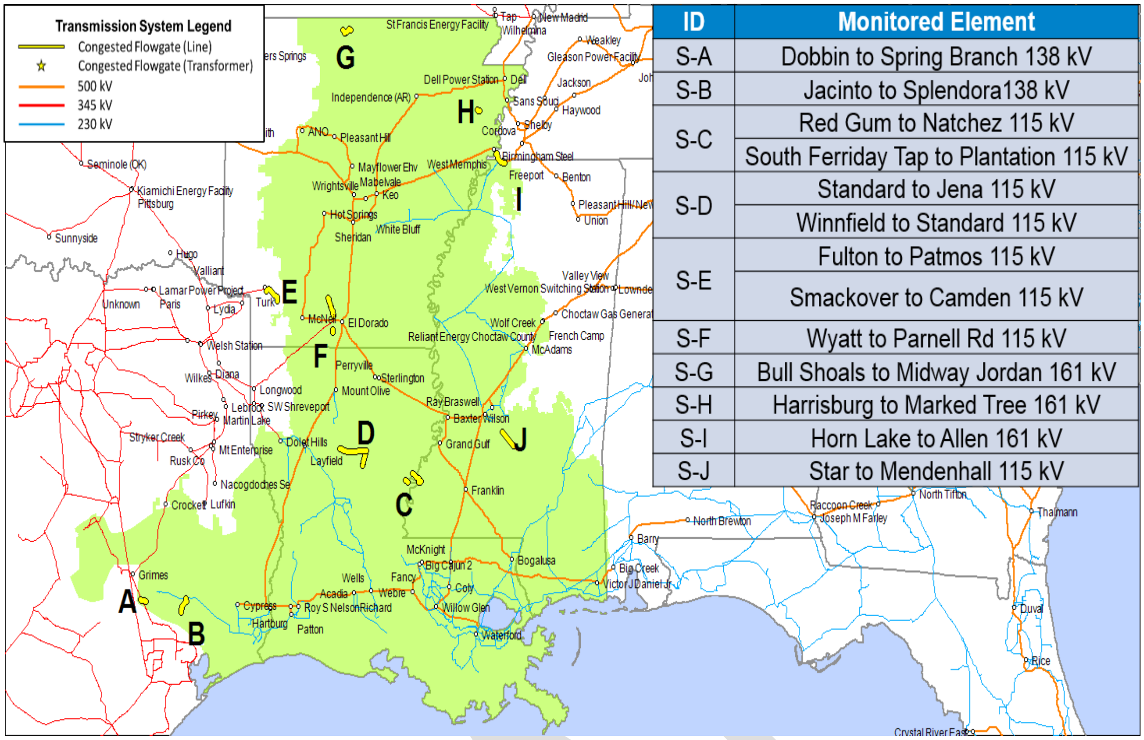
Top Congested Flowgate Analysis

The top congested flowgate analysis identifies system congestion trends based on both the historical market data (day-ahead, real-time, and market-to-market) and out-year production cost model analysis. The MCPS identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams (Figures 5.3-2 and 5.3-3).



*ITCM has plans to improve the Protection and Controls for Adams transformer which would reduce congestion significantly.

Figure 5.3-2: Projected Top Congested Flowgates in MISO North/Central Region



ID	Monitored Element
S-A	Dobbin to Spring Branch 138 kV
S-B	Jacinto to Splendora138 kV
S-C	Red Gum to Natchez 115 kV
	South Ferriday Tap to Plantation 115 kV
S-D	Standard to Jena 115 kV
	Winnfield to Standard 115 kV
S-E	Fulton to Patmos 115 kV
	Smackover to Camden 115 kV
S-F	Wyatt to Parnell Rd 115 kV
S-G	Bull Shoals to Midway Jordan 161 kV
S-H	Harrisburg to Marked Tree 161 kV
S-I	Horn Lake to Allen 161 kV
S-J	Star to Mendenhall 115 kV

Figure 5.3-3: Projected Top Congested Flowgates in the MISO South Region

Project Candidate Identification

Project candidate identification is a partnership between MISO and stakeholders to find 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.

A screening process is used 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. The screening index for each solution is calculated as the ratio between the 15-year-out Adjusted Production Cost (APC) savings and the corresponding project cost:

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

MISO uses a screening index of 0.9 to identify which projects have the greatest potential to provide benefits in excess of cost after further testing and refinement. In addition to identifying the projects with the highest potential, the screening analysis provides 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 solutions that provide the best value under most future outcomes; the reliability assessment ensures system reliability is at least maintained.

Project Cost Estimation

MISO creates cost estimates in order to evaluate transmission solutions in the Market Congestion Planning Study process. To support the creation of cost estimates, MISO developed and published its own cost estimation guide for MTEP18. MISO's cost estimation guide describes the approach and provides the cost data that it uses in developing cost estimates. This document is reviewed yearly with stakeholders.

MISO uses two levels of cost estimate detail: planning-level cost estimates; and scoping-level cost estimates. Planning-level cost estimates are utilized to compare potential projects with the same cost data and the same indicative assumptions. Scoping-level cost estimates are utilized where a project would be eligible for competitive solicitation. MISO's scoping-level cost estimate utilizes the same cost data as its planning-level cost estimates, and refines its assumptions for each specific potential project. For new facilities, MISO performs a desktop analysis to determine project-specific assumptions for it, and for upgrades of existing facilities, MISO consults with the local Transmission Owner to discuss project scope of work assumptions. Scoping-level cost estimates are used as the basis for project recommendation.

In 2018, MISO provided cost estimates for the North/Central focused Market Congestion Planning Study, and for the South focused Market Congestion Planning Study.

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 (2022, 2027 and 2032) 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 or greater

Although prescribed for MEPs, the stated metric and analysis is used to evaluate all economic projects. To arrive at the best solution, projects with a benefit-to-cost ratio of 1.25 or greater 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 and voltage stability; on transient stability as needed; 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.

North/Central Focus Areas

In the North/Central region, the identified 13 top congested flowgates were split into five major focus areas. Those areas are: Dakotas/Minnesota, Wisconsin, Iowa, Northern Indiana and Southern Indiana/Kentucky. A total of 68 solutions were evaluated for the 13 identified flowgates (Table 5.3-2).

2018 N/C MCPS Overview (Number of Solutions)	Dakotas/ Minnesota	Wisconsin	Iowa	Northern Indiana	Southern Indiana /Kentucky
Evaluated	20	10	11	20	7
Passed one-year screening	6	3	2	2	4
Passed 20-year present value analysis	2	3	1	1	1
Project candidates identified	1	1	0	0	1

Table 5.3-2: Summary of MTEP18 MCPS North/Central Solution Evaluation

Dakotas/Minnesota

There were three top congested flowgates identified in the Dakotas/Minnesota focus area (Figure 5.3-4).

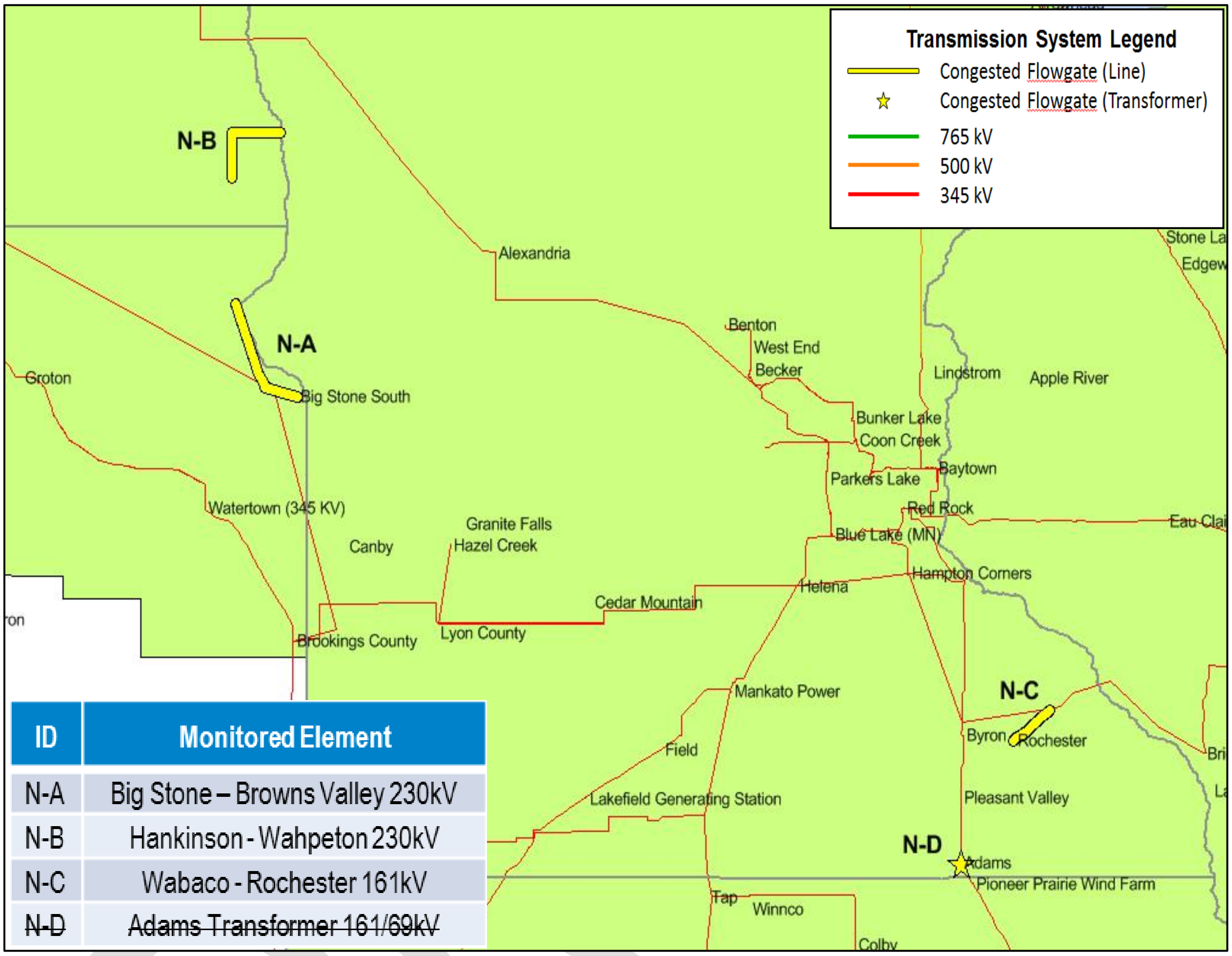


Figure 5.3-4: Dakotas/Minnesota Top Congested Flowgates

On the border of North Dakota/South Dakota and Minnesota, existing and future wind generation located in the Ellendale and Big Stone areas flows east to load centers in the Twin Cities area of Minnesota. Hankinson to Wahpeton 230 kV (N-B, as shown in Figure 5.3-4) and Big Stone to Browns Valley 230 kV (N-A, as shown in Figure 5.3-4) are the two 230 kV lines in the west-to-east flow path. These two lines show binding when any other west-to-east 230 kV or 345 kV line is out. In Southern Minnesota, Wabaco to Rochester 161 kV (N-C, as shown in Figure 5.3-4) is one of the bottle necks in the corridor of west-to-east power transfer from Iowa/Southern Minnesota to Wisconsin. It shows a significant amount of congestion when other 345 kV in the interface of Minnesota to Wisconsin is out.

In total of 20 solutions were evaluated in this area and six of those passed the one-year screening analysis. The six solutions that passed screening were moved forward for present value analysis and the study results as shown in (Table 5.3-3). The costs utilized in present value analysis are the planning-level costs that MISO estimated according to the guidance.

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios to MISO N/C					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Adams - Tremval 345 kV	356.0	1.91	0.13	0.24	0.06	0.50	217.52	N-C: 89%
Adams - North Rochester - Tremval 345 kV	383.0	2.41	0.12	0.23	0.06	0.59	278.68	N-C: 70%
Colby - Adams - North Rochester - Tremval 345 kV	523.0	1.99	0.12	0.23	0.04	0.50	322.29	N-C: 57%
Rebuild Wabaco to Rochester 161 kV	***11.0****	***20.82***	***3.49***	***4.64***	***1.70***	***6.79***	***87.69***	***N-C: 100%***
Upgrade Wavetraps on Hankinson - Wahpeton 230 kV	2.2	24.00	2.99	8.55	0.18	7.88	20.34	N-B: 70%
Rebuild Hankinson - Wahpeton 230 kV	42.3	1.52	0.16	0.44	0.09	0.48	23.99	N-B: 100%

*Scoping-level cost estimation

Table 5.3-3: Dakotas/Minnesota Present Value Analysis Results

Of the two solutions sought to address congestion on Hankinson to Wahpeton 230 kV, rebuilding Hankinson to Wahpeton 230 kV did not pass the present value analysis with a weighted benefit-to-cost ratio of 0.48. Upgrading wavetraps on Hankinson to Wahpeton 230 kV can only address about 70 percent of its congestion. Although it shows a good benefit-to-cost ratio, it leaves a significant amount of the congestion unaddressed and the upgrade will most likely not be enough given the future wind development in the Dakotas and Minnesota border area. Neither of the two solutions was moved forward in the MTEP18 MCPS study cycle. Instead, MISO will continue to evaluate the congestion in this area in future MCPS cycles until MISO can find a more effective long-term solution.

Of the four solutions sought to address congestion on Wabaco to Rochester 161 kV, rebuilding Wabaco to Rochester 161 kV had the highest benefit-to-cost ratio to MISO and fully relieved the congestion. Therefore, it was identified as project candidate 1 (PC-1) and moved forward for further robustness analysis to help inform the project recommendation decision. The rest of the three solutions did not pass the present value analysis due to very high cost.

Contingency analysis was performed on PC-1 to identify any potential new flowgates that may be driven by the project. After selecting PC-1 as the most effective project to address Wabaco to Rochester area congestion, the project candidate went through the economic evaluation, reliability no-harm analysis, and scoping-level cost estimation. As a result of these analyses, PC-1 has been identified as the best-fit project to address Wabaco area congestion. This project fully relieved congestion on Wabaco to Rochester 161 kV while achieving a 6.79 benefit-to-cost ratio to MISO and 1.53 to local TPZ with an estimated cost of $11 million.

Also, various sensitivity analyses were performed to help inform the project's business case under different potential scenarios. A DPP wind sensitivity test evaluated the impact of modeling wind units in the queue with DPP status instead of Regional Generator Outlet Study/Regional Resource Forecast (RGOS/RRF) wind units in Iowa and Southern Minnesota. Under the sensitivity test, rebuilding Wabaco to Rochester 161 kV was shown to be robust and provide a benefit-to-cost ratio of 7.93 and 20-year present value benefit of $102.29 million.

The project of rebuilding the existing Wabaco to Rochester 161 kV is identified as a robust transmission solution and will be recommended as one of the three Economic-Other projects to be included in MTEP18*.*

Iowa

In Iowa there were three identified top congested flowgates (Figure 5.3-5).

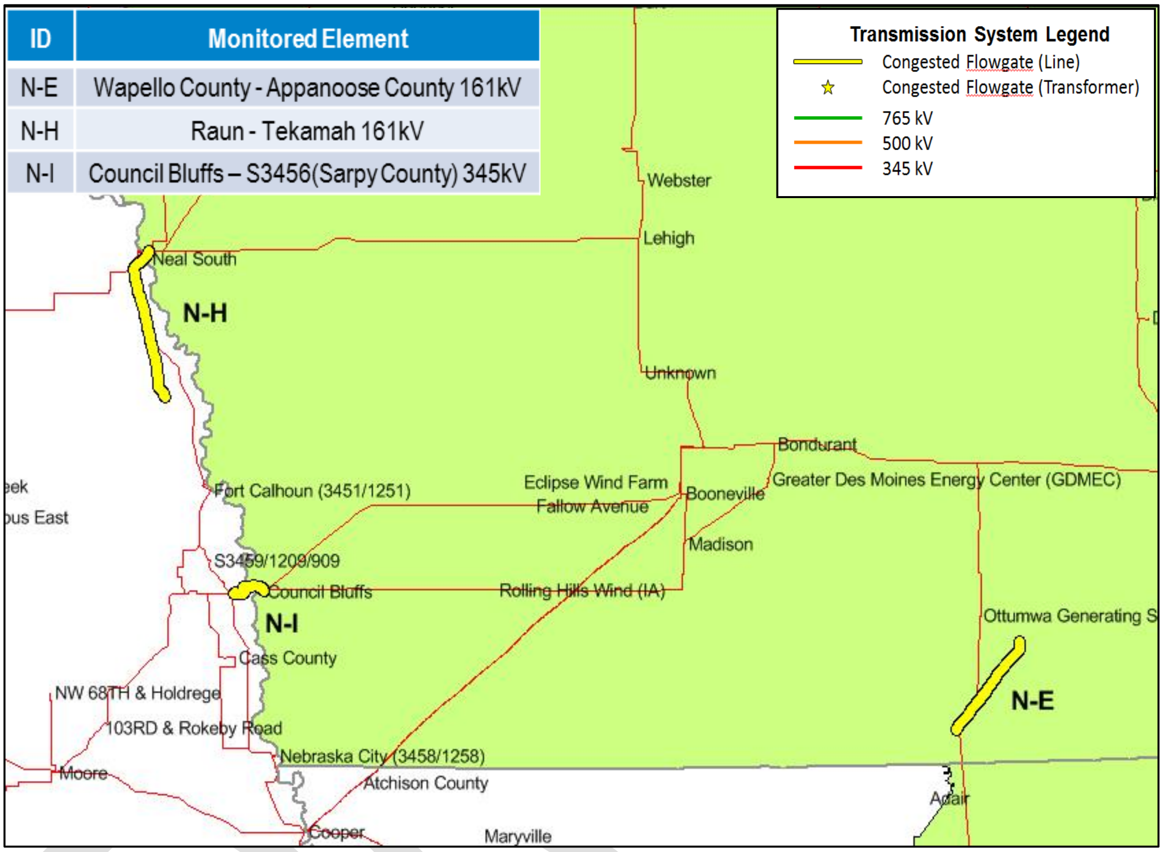


Figure 5.3-5: Iowa Top Congested Flowgates

The congestion in Iowa is due to the high amount of existing and future wind sited in Iowa and in southwestern Minnesota. The flowgates N-H and N-I are on the Iowa-Nebraska border and are aggregated by the power transfer out of Iowa that flows either south or southwest. Raun to Tekamah 161 kV (N-H) is one of lines in the north to south corridor. Existing and future wind generation located in the southwest corner of Minnesota (Split Rock, Buffalo area) increases north-to-south flow on the border. It shows heavy binding under the loss of the 345 kV line in the same flow corridor. In addition, existing and future wind generation located in central and southwest of Iowa flows southwest to the Iowa/Nebraska border through multiple 345 kV lines. Council Bluffs to S3456 (Sarpy County) 345 kV (N-I) shows binding under the loss of any other 345 kV lines in the corridor. Wapello County to Appanoose 161 kV (N-E) is a north-to-south flowgate near the border of Iowa and Missouri. It shows binding when another 345 kV line in the same corridor is out.

In the 2018 MCPS study, a total of 11 solutions were evaluated to address the congestion in Iowa. After the completion of screening and refinement, two out of those 11 solutions passed the initial screening and moved forward to present value analysis (Table 5.3-4).

During the present value analysis, only Council Bluffs–Sarpy County 345 kV terminal equipment upgrade passed 1.0 benefit-to-cost ratio. Although this solution provided high APC savings to MISO and fully relieved the congestion on flowgate N-I, the terminal equipment that will be upgraded is a non-MISO facility. It could be further evaluated in the next MISO and Southwest Power Pool (SPP) interregional study and will not move forward for further analysis in the MTEP18 MISO MCPS study.

Transmission Solution	Cost Estimate (2018-$M)	Benefit–to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
New substation at the intersection Raun - Hoskins 345kV & Emerson - Bancroft 115 kV	18.0	1.56	0.01	0.54	0.21	0.50	11.11	N-H: 30%
Council Bluffs - Sarpy County 345 kV terminal equipment upgrade at Sarpy County	3.0	48.57	4.30	9.24	0.17	13.36	49.20	N-I: 100%

Table 5.3-4: Iowa Area Present Value Analysis Results

Therefore, no project will be recommended in Iowa area in MTEP18 MCPS. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

Wisconsin

In Wisconsin there were two identified top congested flowgates (Figure 5.3-6).

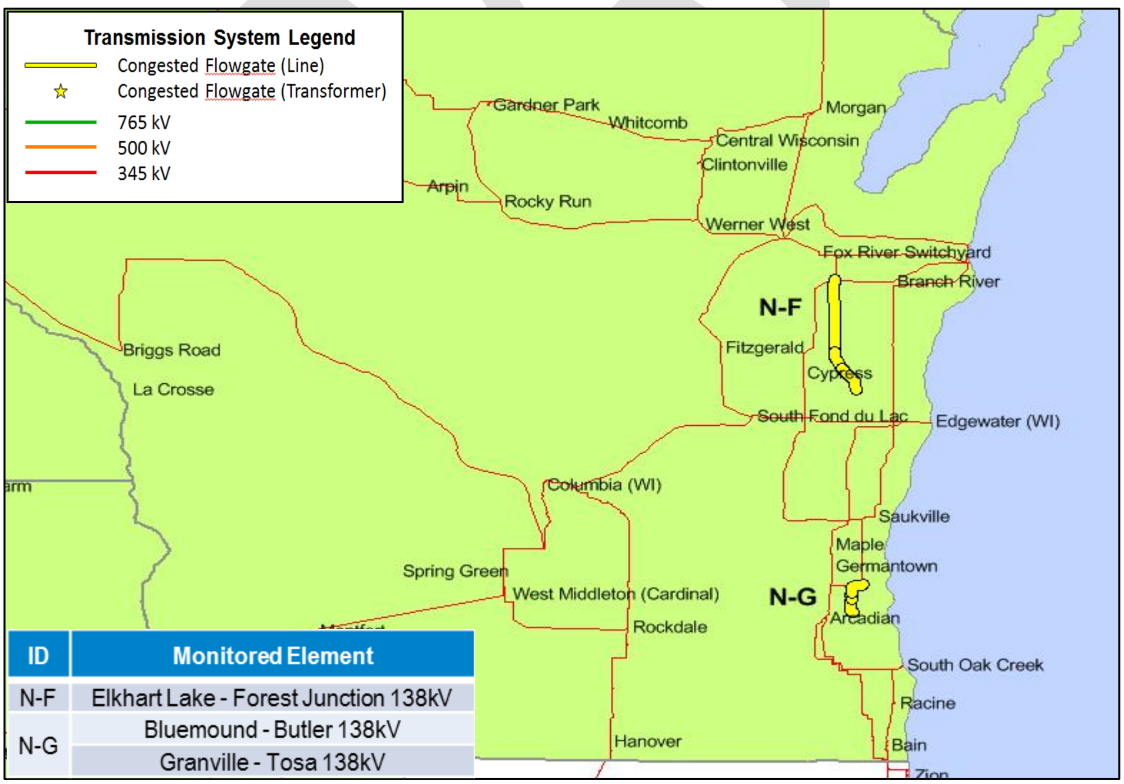


Figure 5.3-6: Wisconsin Top Congested Flowgates

The congestion in Wisconsin is caused by low-cost generation in the northern part of the state paired with retirements in the southern part of the state. Forest Junction to Elkhart Lake 138 kV (N-F, as shown in Figure 5.3-6) is one of the lines in the north-to-south flow corridor. It shows binding under the loss of any other parallel 345 kV lines. Bluemound to Butler 138 kV and Granville to Tosa 138 kV lines are in the north-to-south corridor between Edgewater and South Oak Creek substations, as well. This flow corridor becomes congested under loss of any 345 kV line allowing north-to-south flow.

A total of 10 solutions were submitted to address the congestion in Wisconsin. After the completion of screening and refinement, three out of 10 solutions passed the screening and moved forward for present value analysis (results as shown in Table 5.3.-5).

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Move Elkhart Lake Load to Parallel 138 kV Circuit (Lyndon - Esker View)	1.5	7.77	(0.30)	1.27	2.08	2.30	4.24	N-F: 27%
Add Series Reactor on Elkhart Lake - Forest Junction 138 kV	***2.0****	***13.86***	***1.23***	***2.17***	***(0.53)***	***3.55***	***8.72***	***N-F: 89%***
Move Elkhart Lake Connection to Esker View - Lyndon 138 kV and add series reactor on Elkhart Lake	3	6.81	0.38	0.91	1.21	2.00	7.38	N-F: 76%

*Scoping-level cost estimation

Table 5.3-5: Wisconsin Area Present Value Analysis Results

During the present value analysis, all three solutions passed the 1.0 benefit-to-cost ratio. However, adding a series reactor on the Forest Junction to Elkhart Lake 138 kV line was moved forward as Project Candidate 2 (PC-2) because of the highest benefit-to-cost ratio and its ability to address the highest percentage of congestion on flowgate N-F.

Contingency analysis was performed on PC-2 to identify any potential new flowgates that may be driven by the project. After selecting PC-2 as the most effective project to address Forest Junction to Elkhart Lake area congestion, it went through the economic evaluation, reliability no-harm analysis, and scoping level cost estimation. As a result of these analyses, PC-2 has been identified as the best-fit solution to address congestion in the area. This project relieved 90 percent of the congestion on the line while achieving a 3.55 benefit-to-cost ratio to MISO and 5.62 to local TPZ with an estimated cost of $2 million.

In conclusion, the project of adding series reactor on Forest Junction to Elkhart Lake 138 kV will be recommended as one of the three Economic-Other projects to be included in MTEP18.

Northern Indiana

There were three top congested flowgates identified in the Northern Indiana area (Figure 5.3-7).

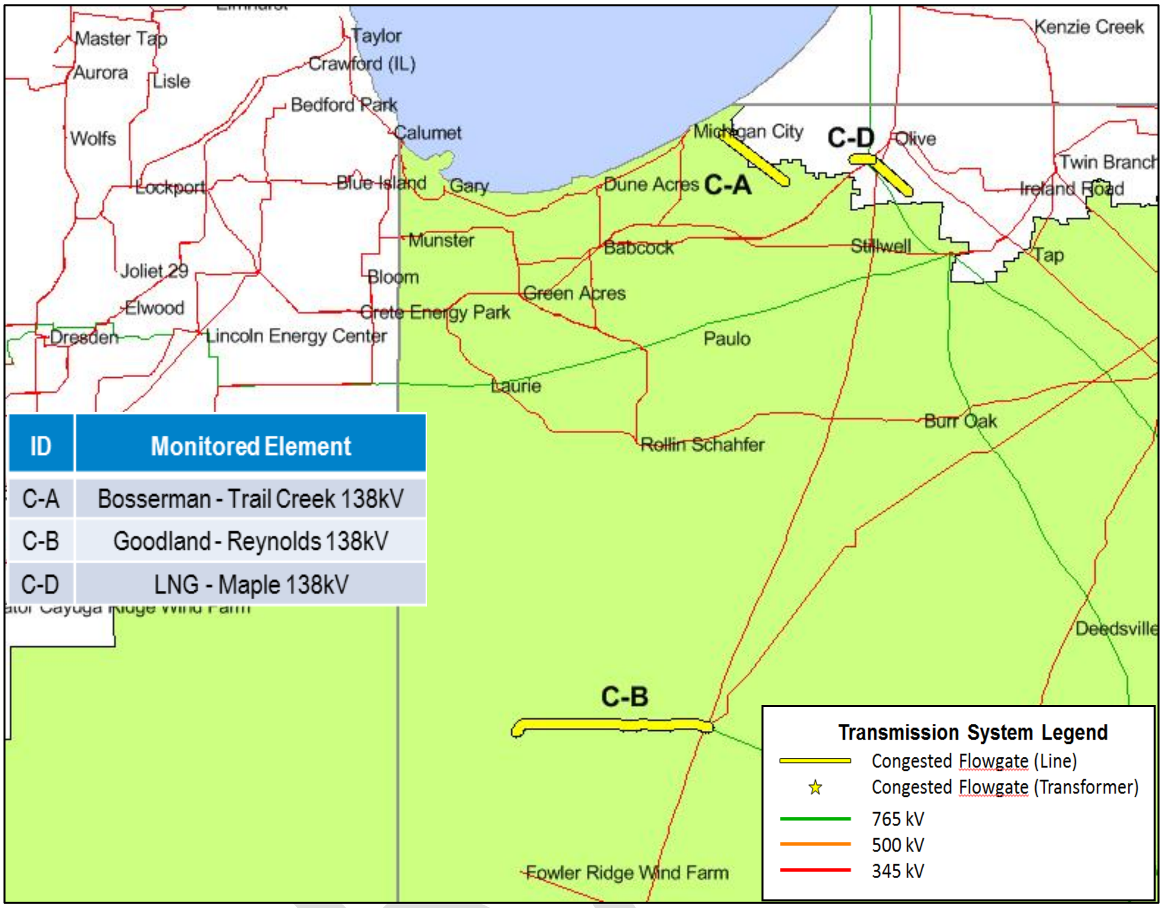


Figure 5.3-7: Northern Indiana Top Congested Flowgates

The main driver of congestion on Bosserman to Trail Creek 138 kV and LNG to Maple 138 kV is the increasing load in Michigan City area being served by generators located to the east and northeast. This leads to heavier east-to-west flows on the 138 kV system. The congestion on the Goodland to Reynolds 138 kV flowgate is driven by existing and future wind farms located west of the constraints and near the border of Illinois and Indiana.

A total of 20 solutions were evaluated in Northern Indiana area. Two out of 20 solutions passed the initial screening, both addressing congestion on Bosserman to Trail Creek 138 kV. Out of these two projects, the project to upgrade conductors on three lines (Michigan City to Trail Creek, Trail Creek to Bosserman 138 kV and LNG to Maple 138 kV) were selected as Project Candidate 3 (PC-3) and moved forward for robustness analysis. No projects near the Goodland–Reynolds 138 kV flowgate passed screening because the high costs of potential projects in the area outweighed the benefits.

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Reconductor Michigan City - Trail Creek - Bosserman 138 kV and LNG - Maple 138 kV	8.5	1.43	1.84	1.33	0.92	1.40	15.29	C-A: 96% C-D: 100%
Duplicate Bosserman – Michigan City 138 kV	15.0	0.89	1.28	1.25	0.48	0.99	18.27	C-A: 100%

Table 5.3-6: Northern Indiana Area Present Value Analysis Results

In the robustness analysis phase, PC-3 would not be recommended because it does not provide benefits in excess of cost to the local transmission owner (Table 5.3-6). Therefore, no project will be recommended in the Northern Indiana area for Board of Director approval. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

Southern Indiana/Kentucky

There were three top congested flowgates identified and grouped as flowgate C-C in Southern Indiana (Figure 5.3-8).

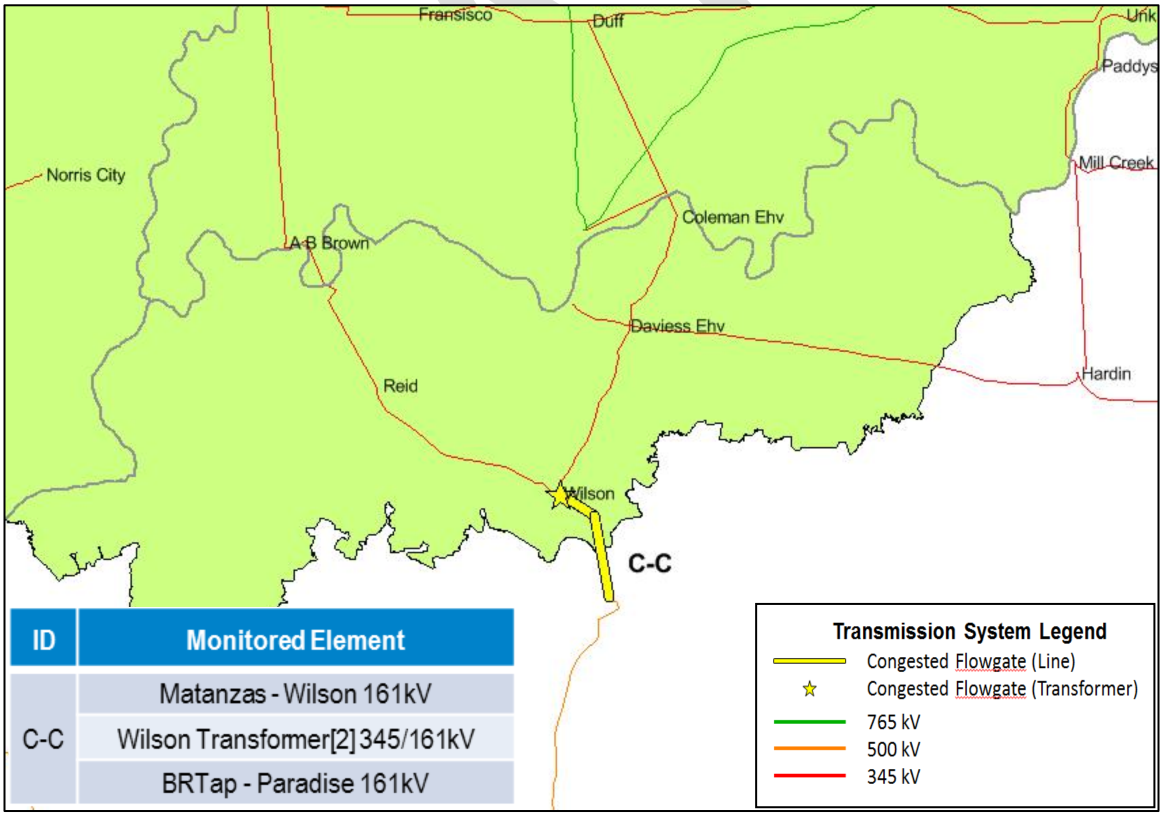


Figure 5.3-8: Southern Indiana/Kentucky Top Congested Flowgates

The congestion in Southern Indiana and Kentucky area is caused by the increased north-to-south flow between MISO and Tennessee Valley Authority (TVA). The flowgates listed above are on the border of MISO and TVA. This flow corridor becomes congested when higher north-to-south flow comes from MISO into TVA. Loss of one line or transformer causes congestion on other parallel flow paths near the seam. The congestion will be aggregated by retiring some generation in TVA area.

In the 2018 MCPS study, there were seven submitted solutions addressing the congestion in Southern Indiana and Kentucky area. Of those, four passed the screening (Table 5.3-7).

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Wilson – BR Tap 161 kV, Reconductor BR Tap -Paradise 161kV and Remove BR Tap Switch	***16.0****	***4.26***	***2.53***	***5.04***	***1.65***	***3.28***	***61.60***	***C-C: 78%***
Wilson - Matanzas - Paradise 161 kV	45	1.41	0.84	1.57	0.49	1.05	55.34	C-C: 45%
Wilson - Paradise 161 kV	45	1.52	0.89	1.56	0.57	1.1	58.3	C-C: 50%
Wilson – BR Tap 161 kV, Reconductor BR Tap - Paradise 161 kV, Remove BR Tap Switch add 3rd Wilson 345/161 transformer	47.5	1.44	0.83	1.82	0.55	1.13	62.83	C-C: 100%

*Scoping-level cost estimation

Table 5.3-7: Southern Indiana/Kentucky Area Present Value Analysis Results

During the present value analysis, the first proposal was selected as Project Candidate 4 (PC-4). This proposal could fully address the congestion on Wilson to Matanzas and BR Tap to Paradise lines with the highest benefit-to-cost ratio among the four solutions.

Contingency analysis was performed on PC-4 to identify any potential new flowgates that may be driven by the project. After selecting PC-4 as the most effective project to address Wilson and BR Tap area transmission congestion, it went through the economic evaluation, reliability no-harm analysis and scoping level cost estimation. As a result of these analyses, PC-4 has been identified as the best-fit project to address congestion in the area. This project fully relieved congestion on Wilson to Matanzas and BR Tap to Paradise lines while achieving a 3.28 benefit-to-cost ratio to MISO and 1.73 to local TPZ with an estimated cost of $16 million.

In conclusion, the project of adding new Wilson to BR Tap 161 kV line, re-conductoring BR Tap to Paradise 161 kV, upgrading terminal equipment at Matanzas and removing switch at BR Tap will be recommended as one of the three Economic-Other projects to be included in MTEP18..

South Focus Areas

In the South region, the 10 identified top congested flowgates were split into four major focus areas by state. Those areas are: Texas, Louisiana, Arkansas and Mississippi. A total of 48 solutions were evaluated for the 10 identified flowgates (Table 5.3-8).

2018 South MCPS Overview (Number of Solutions)	Texas	Louisiana	Arkansas	Mississippi
Evaluated	12	19	12	5
Passed one-year screening	0	5	0	0
Passed 20-year present value analysis	0	5	0	0
Project candidates identified	0	0	0	0

Table 5.3-8: MISO South top congested flowgates evaluated (by state)

Texas

There were two congested flowgates identified in the West of Atchafalaya Basin (WOTAB) and Western area of Texas (Figure 5.3-9). Congestion was driven by new generation as well as MTEP-approved projects shifting congestion in the area. After identifying economic congestion in the area, MISO worked with the local TO on modifications to MTEP17 Appendix A Project P12096. The withdrawal of P12096 (Dobbin Auto Project), replaced with P15105 (Dobbin 138 kV Line Breakers) and P15106 (Fish Creek–Ponderosa 138 kV Reconductor), reduced economic congestion within the Texas WOTAB/Western area. After the modification of the Appendix A project the flowgates in the Texas area would not have met the threshold for top congested flowgates.

There were 12 projects studied to address congestion on the flowgates in Texas. After the Appendix-A project modifications, congestion was not sufficient for the justification for the solutions received.

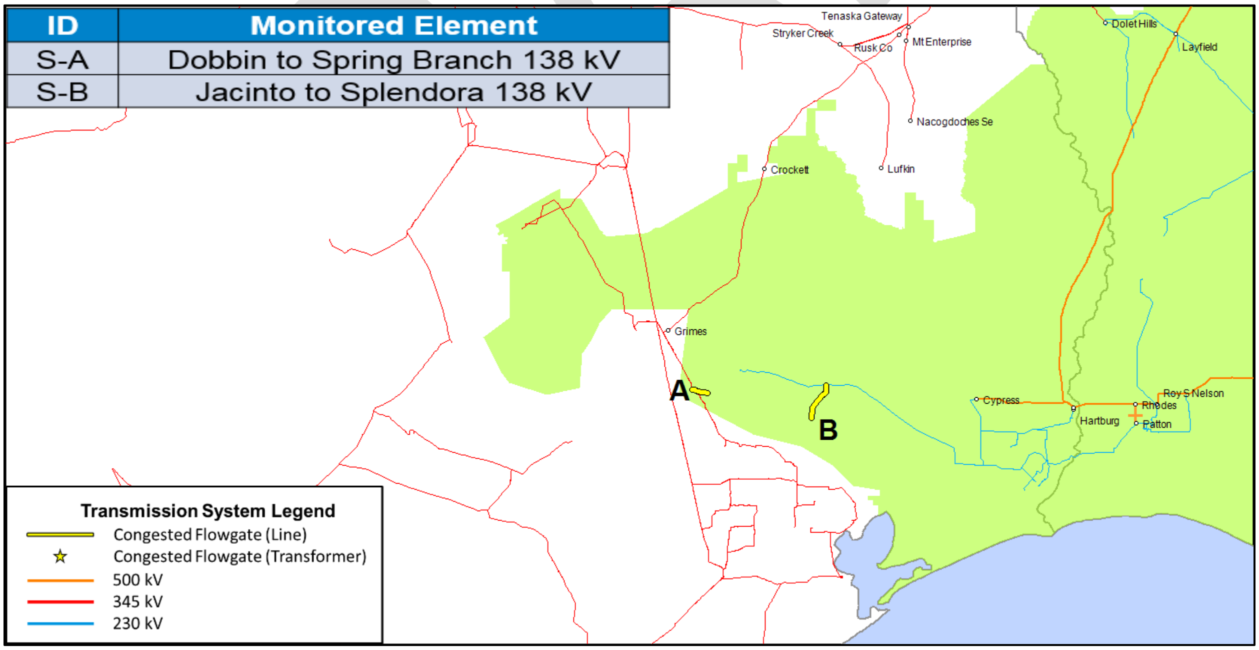


Figure 5.3-9: Texas Top Congested Flowgates

Louisiana

There were two congested flowgates identified in the state of Louisiana (Figure 5.3-10). Flowgate S-C —: Red Gum to Natchez and South Ferriday Tap to Plantation — are located on the Louisiana-Mississippi border. The identified congestion was influenced by the assumed retirements and replacement generation at Sterlington and Baxter Wilson substations in addition to high west (Perryville) to east (Baxter Wilson) transfers under contingent conditions. Flowgate S-D congestion levels were driven by the loss of the 500 kV system increasing congestion on the lower kV transmission system.

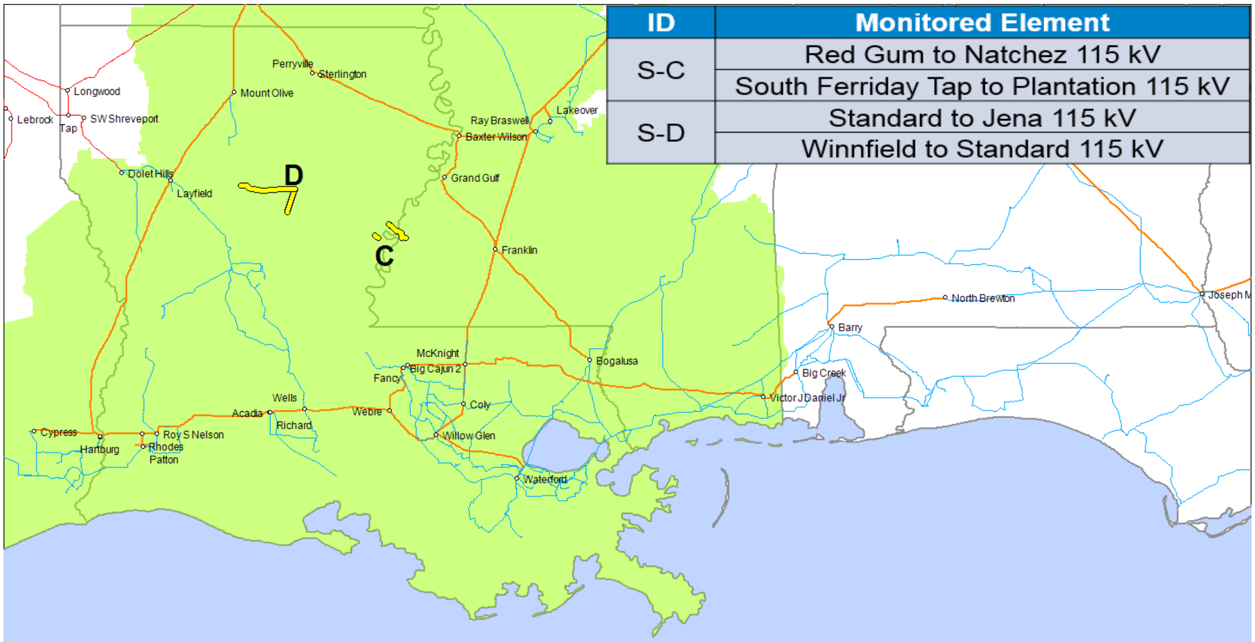
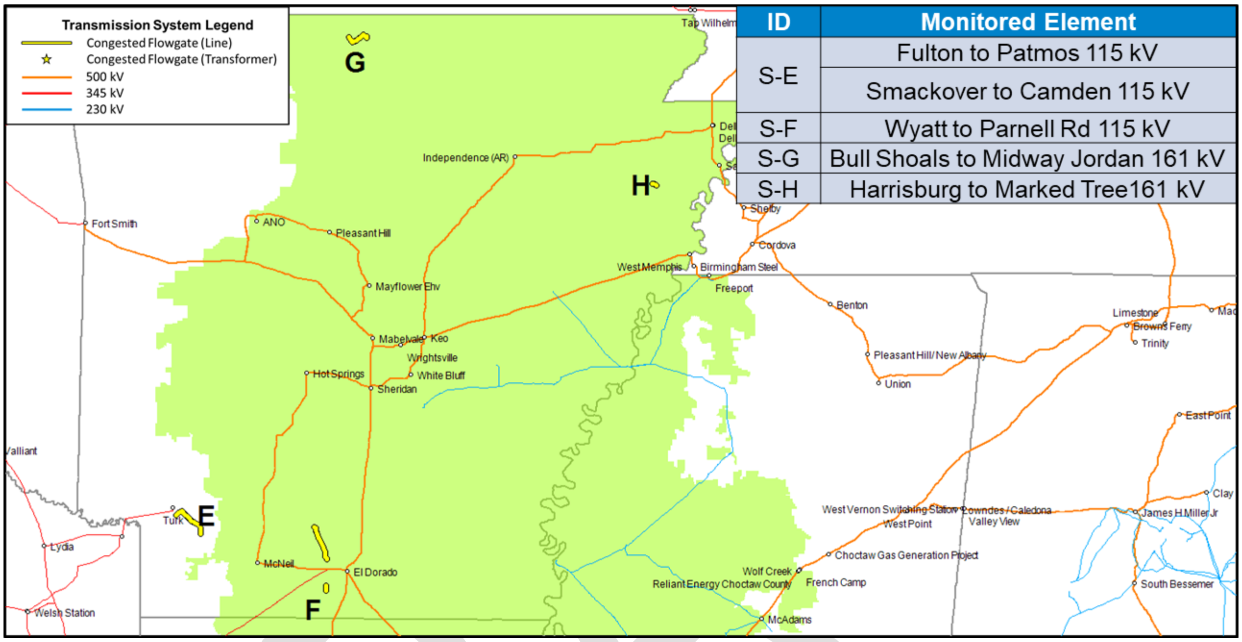


Figure 5.3-10: Louisiana Top Congested Flowgates

There were 19 projects studied to address congestion on the flowgates in Louisiana. Of those 19 projects five passed screening addressing flowgate S-C. The five solutions studied addressing this flowgate included a Target Appendix-A Baseline Reliability Project. After conducting robustness analysis on these five projects, the BRP rebuild of Natches SES – Red Gum was the most effective at resolving the reliability and economic congestion issues. While addressing both the reliability and economic congestion, this project did not meet the benefit-to-cost ratio of 1.25 and will therefore be categorized as a Baseline Reliability Project.

Arkansas

There were four congested flowgates identified in the state of Arkansas (Figure 5.3-11). Flowgates were spread across the state with congestion showing up on flowgates on or close to the MISO seam. Congestion on the top flowgates in Arkansas are largely driven by retirements with limited replacement assumptions and are affected by contingencies for the heavy flows due to the loss of a nearby 500 kV transmission element.



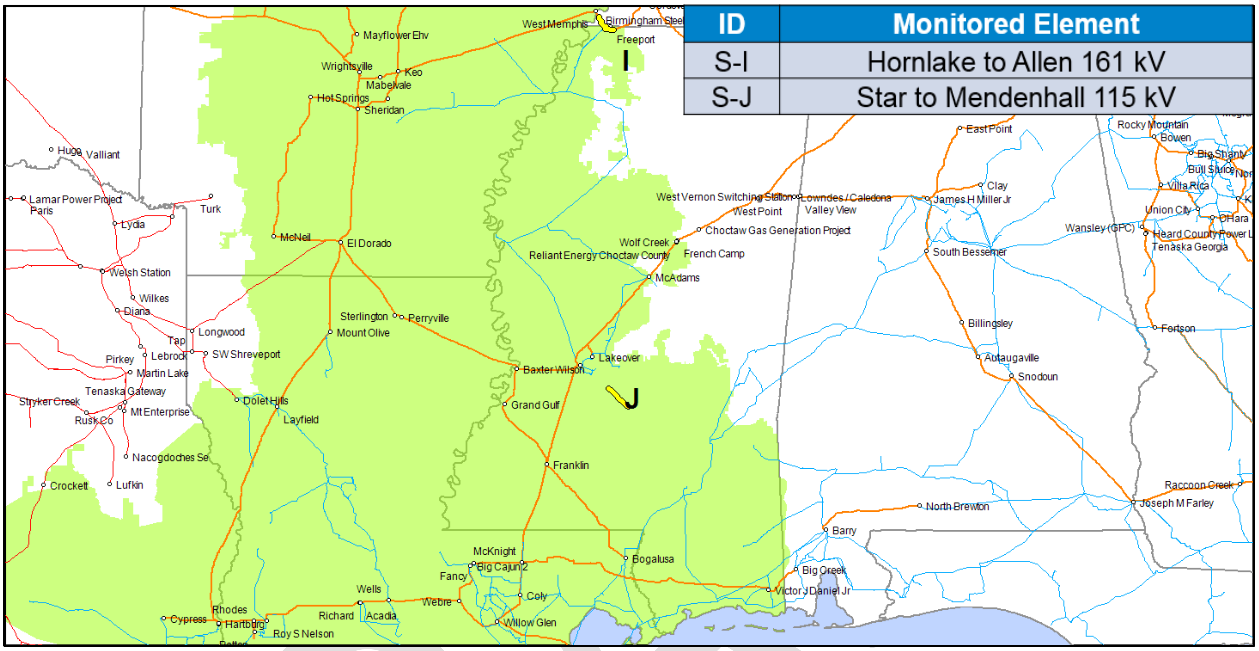
ID	Monitored Element
S-E	Fulton to Patmos 115 kV
	Smackover to Camden 115 kV
S-F	Wyatt to Parnell Rd 115 kV
S-G	Bull Shoals to Midway Jordan 161 kV
S-H	Harrisburg to Marked Tree161 kV

Figure 5.3-11: Arkansas Top Congested Flowgates

There were 12 projects studied to address congestion on the flowgates in Arkansas. Some of the projects aimed at rebuilding the congested flowgates with higher ratings while others had new area network upgrades that helped relieve congestion on the listed flowgates. There were also 500 kV project ideas close to the MISO-SPP seams that were studied. Though some of the projects did reduce congestion on the flowgates, none were cost effective enough to clear the 0.9 screening benefit-to-cost ratio threshold. Flowgates will be closely monitored for any change in congestion patterns in future MCPS cycles.

Mississippi

There were two congested flowgates identified in the state of Mississippi (Figure 5.3-12). Flowgates were along the MISO seam with TVA and SERC Reliability Corp. Congestion on the top flowgates in Mississippi are largely driven by retirements in TVA and cross-border flows into the SERC region due to load growth.



ID	Monitored Element
S-I	Hornlake to Allen 161 kV
S-J	Star to Mendenhall 115 kV

Figure 5.3-12: Mississippi Top Congested Flowgates

There were five projects studied to address congestion on the flowgates in Mississippi. Some of the projects aimed at rebuilding the congested flowgates with higher ratings while others had new area network upgrades that helped relieve congestion on the listed flowgates. There were also 500 kV project ideas close to the MISO-TVA and MISO-SOCO seams that were studied. Though some of the projects did reduce congestion on the flowgates, none were cost effective enough to clear the 0.9 screening benefit-to-cost ratio threshold. Flowgates will be closely monitored for any change in congestion patterns in future MCPS cycles.