Appendix F

MISO Transmission Expansion Plan 2016 with Select Appendices

MTEP16

MISO Transmission Expansion Plan

Table of Contents

Executive Summary

Introduction

MISO is focused on ensuring a reliable and efficient electric infrastructure to meet future needs

System Planning is working to ensure a reliable and efficient infrastructure given a changing resource mix

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

The electricity industry successfully navigated a tremendous amount of change and uncertainty over the last decade and faces continued change into the foreseeable future. MISO's strategy is meant to ensure its market operations and electric infrastructure will meet tomorrow's needs. MISO System Planning plays a key role in the development of new planning methods, providing critical insights around impacts of change, and recommending new transmission infrastructure to support ongoing transformation of the regional landscape. MTEP16 reflects current progress in long-term planning efforts to deliver the lowest-cost energy to consumers and maintain reliable operation of the transmission system as well as set a path for future needs.

MTEP16 Overview

In MTEP16, MISO staff recommends the MISO Board of Directors approve $2.7 billion of new transmission expansion projects with expected in-service dates through 2024. MTEP16, the 13th edition of this publication, is the culmination of more than 18 months of collaboration on system planning across a diverse geographic and regulatory landscape covering 900,000 square miles. The projects in MTEP16 bring continued reliability to the electric grid and deliver the lowest-cost energy to customers.

> In MTEP16, the 13th edition of this publication, MISO staff recommends $2.7 billion of new transmission expansion projects for Board of Directors' approval

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

- Continued efforts to evaluate transmission needs and identify solutions through Market Congestion Planning Studies[1]
- Providing transparency around the Resource Adequacy outlook in the MISO Region[2]
- Greater interregional planning collaboration along MISO's seams[3]
- Seeking improved Generation Interconnection Process outcomes through Queue Reform[4]
- MISO's Clean Power Plan analysis[5]

MTEP16 is organized into four books and a series of detailed appendices.

- **Book 1** summarizes this cycle's projects and the analyses behind them
- **Book 2** describes annual and targeted analyses for Resource Adequacy
- **Book 3** presents the policy landscape. It summarizes regional and interregional studies
- **Book 4** presents additional regional energy information

Appendices A through F provide detailed assumptions, results, project information and stakeholder feedback.

MTEP16 Highlights

- **383 new projects** for inclusion in Appendix A
- **$12.9 billion in projects** constructed in the MISO region since 2003
- **MISO forecasts the reserve margin** will drop below the Planning Reserve Margin Requirement of 15.2 percent beginning in 2018 absent additional actions by load serving entities and state commissions
- Improved **Interregional Planning** pursuant to Order 1000

1 See MTEP16 Report, Section 5.3
2 See Book 2
3 See Chapter 8
4 See Section 4.2
5 See Section 7.1

The MISO Planning Approach

A defined set of principles, established by MISO's Board of Directors, is the foundation of the organization's planning efforts. These principles, last reconfirmed March 2016, were created to improve and guide transmission investment in the region and to give strategic direction to the MISO transmission planning process.

Guiding Principles for Expansion Plans

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

In support of these goals, the MISO regional expansion planning process should meet each of the following Guiding Principles[6]:

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

The MTEP process seeks to identify projects which:

- Ensure the reliability of the transmission system
- Provide economic benefits, such as increased market efficiency
- Facilitate public policy requirements, such as meeting Renewable Portfolio Standards
- Address other issues or goals identified through the stakeholder process

A number of conditions must be met through this process before approving long-term transmission that will support future generation growth and accommodate documented energy policy mandates and laws. These conditions support the MISO guiding principles and include:

[6] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, March 2013, and March 2016

- A robust business case for the project
- Policy consensus around what issue is being addressed
- Clearly defined cost allocation methods that closely align who pays with who benefits, and Cost recovery mechanisms that reduce financial risk

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

Competitive Transmission Process

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

In response to these significant changes, MISO's Competitive Transmission Process,[7] consisting of the Competitive Developer Qualification Process and the Competitive Developer Selection Process, was designed to supplement the established regional transmission planning process (Figure 1.1). As a result, the MTEP process continues to determine the facilities necessary to ensure delivery of lowest-cost energy to consumers and the reliable operation of the transmission system while the MISO Competitive Developer Selection Process determines the responsible entity that will construct, own, operate and maintain these facilities.

MTEP15 included a Competitive Transmission Facility that triggered the first implementation of the MISO Competitive Developer Selection Process. This process began with the issuance of a Request for Proposals (RFP) for the Duff-Coleman EHV 345 kV transmission line facility on January 8, 2016. MISO received 11 completed proposals in response to this RFP to construct, own, operate and maintain the Duff-Coleman EHV 345 kV transmission line facility. These proposals are under evaluation by MISO, which is expected to be completed on or before December 30, 2016.

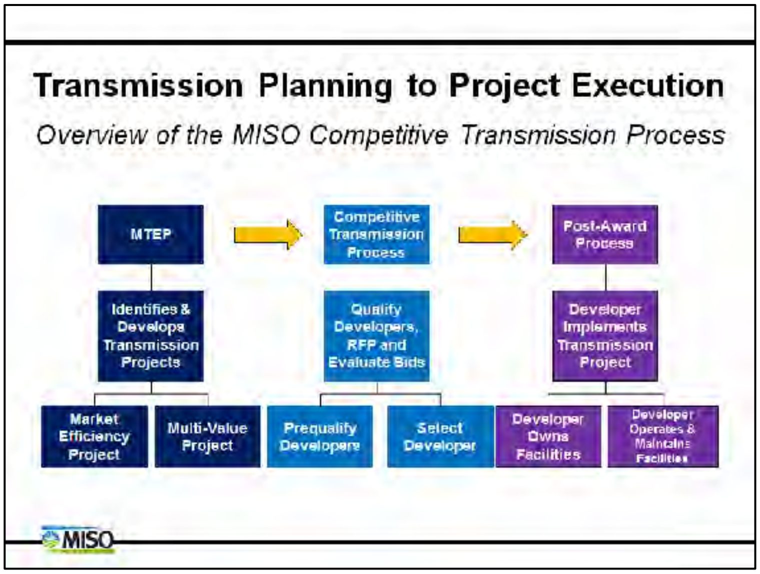


Figure 1.1: Overview of MISO Competitive Transmission Process

MTEP16 does not include any transmission facilities eligible for the MISO Competitive Developer Selection Process, however this cycle will include a Market Efficiency Project (MEP) located wholly within the state of Minnesota.[8] The MTEP16 MEP was not eligible for the MISO Competitive Developer Selection Process due to the applicability of Minnesota Statute 216B.246, which assigns the authority for selecting developers to the state.

[7] https://www.misoenergy.org/PLANNING/Pages/TransDevQualSel.aspx
[8] See Section 5.3 Market Congestion Planning Study

The System Planning Long-Term Plan

The MISO Strategic Plan includes three Strategic Objectives: Market and Grid Positioning, Serve and Grow Membership and Thought Leadership (Figure 1.2). These key objectives — in conjunction with a focus on ensuring efficient and effective processes, development of necessary employee skill sets and implementation of new technology — collectively seek to achieve MISO's vision to be the most reliable, value-creating regional transmission organization (RTO). The MISO long-term strategic plan sets the framework to address upcoming challenges in the industry with a clear, forward-looking roadmap.

MISO System Planning will undertake a number of initiatives in support of key elements of the MISO strategic plan, with a goal of ensuring an electric system that provides reliable, low-cost energy to customers.

The MISO Strategic Plan

Figure 1.2: The MISO Strategic Plan

Portfolio Evolution / Enable Infrastructure Investment

Transmission infrastructure is expected to be a key component of ensuring reliable and low-cost electricity given the changes in the resource portfolio. The MISO footprint will see a decrease in coal generation resources and an increase in other generation resources such as natural gas, wind and solar. Additionally, load patterns will likely shift due to increased energy efficiency, demand response and distributed generation. The MISO transmission overlay development process will identify transmission projects to reliably deliver least-cost energy and capacity to consumers under a range of foreseeable resource mix scenarios. This work will be accomplished by building on the three future scenarios detailed in MTEP16[9] and using them to develop long-term transmission planning roadmaps, which will guide annual transmission decisions through the MTEP process in future MTEP cycles.

Another significant aspect of portfolio evolution is the need to interconnect new generation resources in an efficient manner. Continued focus on generator interconnection queue reform will improve study processes to allow timely execution of Generation Interconnection Agreements and align with participation in MISO's resource adequacy construct. Executing this essential planning function will address generation portfolio changes and support resource adequacy throughout the MISO footprint.

Finally, MISO will continue to provide insight around resource adequacy in the region. With shrinking reserve margins, continued transparency around the supply/demand balance remains important to understand reliability risk for the MISO footprint. Additional work to refine the calculation of the required reserve margin will also occur to ensure the analysis reflects the new mix of resource types including reduced levels of baseload coal, increased intermittent resources such as wind, and the introduction of new resource types such as storage to the MISO footprint.

Regional Modeling and Analytics

New energy policies and emerging technologies such as energy storage, solar, and synchrophasors are changing the bulk electric system. MISO will help state regulators and members understand the risks and value created by changes in economic and policy conditions by providing data transparency and offering technical analysis. In the MTEP16 timeframe,[10] MISO completed analysis of the Clean Power Plan (CPP) and other environmental regulations to assess the impacts of compliance with the CPP's CO_2 reduction targets. Going forward, MISO will continue to focus its analysis on impacts of carbon regulations, including air quality rules, and emerging alternative technologies such as energy storage and distributed generation. Ultimately MISO will consider how to incorporate these complexities into MISO's planning process.

Electric-Gas Coordination

As gas-fired generation becomes an increasingly larger part of the MISO resource mix, MISO will coordinate with the natural gas industry to address issues associated with the region's increasing reliance on gas-fired power generation. From a System Planning perspective, MISO will continue to analyze impacts of long-term increases in natural gas for electricity-generating purposes. In addition, MISO will focus on the development of additional skills, tools and processes needed to understand the expected supply of natural gas so accurate transmission planning solutions are developed. Future studies included in MTEP will reflect this increased integration of gas impacts into transmission planning.

Seams Optimization

Interregional planning is critical to maximize the value of the transmission system and deliver savings for customers. Interregional studies[11], conducted jointly with MISO's neighboring planning regions, are based on a review of transmission issues conducted annually. Additionally, efforts such as the Targeted Market Efficiency Projects[12] concept, currently in development with PJM, reflect continued innovation in the process to ensure MISO and its neighbors jointly identify new or better projects than would otherwise be

[9] See Section 5.2
[10] See Section 7.1
[11] See Chapter 8 Interregional Studies
[12] See Section 8.1 PJM Interregional Study

developed through the regional plan. MISO and PJM have identified a number of potential projects of this type and anticipate filing Joint Operating Agreement changes along with associated regional tariff revisions with FERC near the end of the fourth quarter of 2016.[13] Along the seam with SPP, MISO has committed to a joint, multi-year study, similar to MISO's own overlay development efforts, which will address future interregional system planning needs stemming from a dramatically changing future energy landscape expected to impact both RTOs. MISO will also continue to work with the Southeastern Regional Planning (SERTP) sponsors to advance and mature interregional coordination provisions that were accepted by FERC in 2016.

Conclusion

MISO is proud of its independent, transparent and inclusive planning process that is well-positioned to study and address future regional transmission and policy-based needs. The valuable input and support from the stakeholder community allows MISO to create well-vetted, cost-effective and innovative solutions to provide reliable delivered energy at the least cost to consumers. MISO welcomes feedback and comments from stakeholders, regulators and interested parties on the evolving electricity system and implementation of MISO's strategic initiatives. For detailed information about MISO, MTEP16, renewable energy integration, cost allocation, and other planning efforts, go to www.misoenergy.org.

[13] See Section 8.1 PJM Interregional study - IPSAC

Book 1
Transmission Planning Studies

2016

Chapter 2

MTEP16 Overview

2016

2.1 Investment Summary

The 383 MTEP16 new Appendix A projects represent $2.69 billion[14] in transmission infrastructure investment and fall into the following categories:

- **106 Baseline Reliability Projects (BRP) totaling $691.2 million —** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **32 Generator Interconnection Projects (GIP) totaling $142.7 million** — GIPs are required to reliably connect new generation to the transmission grid.
- **1 Market Efficiency Project (MEP) totaling $108 million** — MEPs meet Attachment FF requirements for reduction in market congestion.
- **1 Transmission Delivery Service Project (TDSP) totaling $350,000** — TDSPs are Network Upgrades driven by Transmission Service Requests (TSR).
- **243 Other Projects totaling $1.75 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.

The largest 10 projects represent 24 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

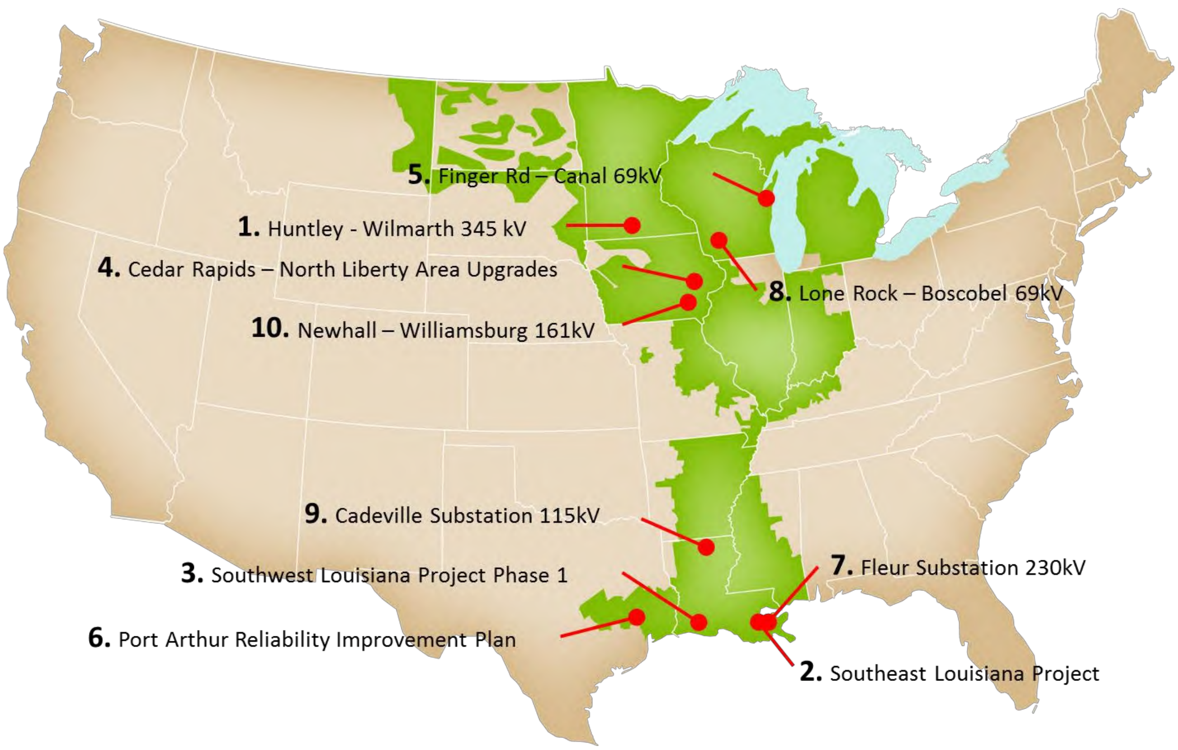


Figure 2.1-1: Top 10 MTEP16 new Appendix A projects (in descending order of cost)

[14] The MTEP16 report and project totals reflect all project approvals during the MTEP16 cycle, including those approved on expedited project review basis prior to December 2016.

The new projects recommended for approval in MTEP16 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP16 Appendix A contain 10 cost-shared Generator Interconnection Projects. Cost sharing information is provided in Chapter 2.2.

Region	Baseline Reliability Project (BaseRel)	Generator Interconnection Project (GIP)	Market Efficiency (MEP)	Transmission Delivery Service Project (TDSP)	Other	Total
Central	$8,208,000	$0	$0	$0	$151,331,000	$159,539,000
East	$59,690,000	$81,033,000	$0	$0	$423,297,000	$564,020,000
West	$147,026,000	$42,776,000	$108,000,000	$350,000	$728,654,000	$1,026,806,000
South	$476,297,000	$18,962,000	$0	$0	$443,881,000	$939,140,000
Grand Total	**$691,221,000**	**$142,771,000**	**$108,000,000**	**$350,000**	**$1,747,163,000**	**$2,689,505,000**

Table 2.1-1: MTEP16 New Appendix A investment by project category and planning region

Other Project Type

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

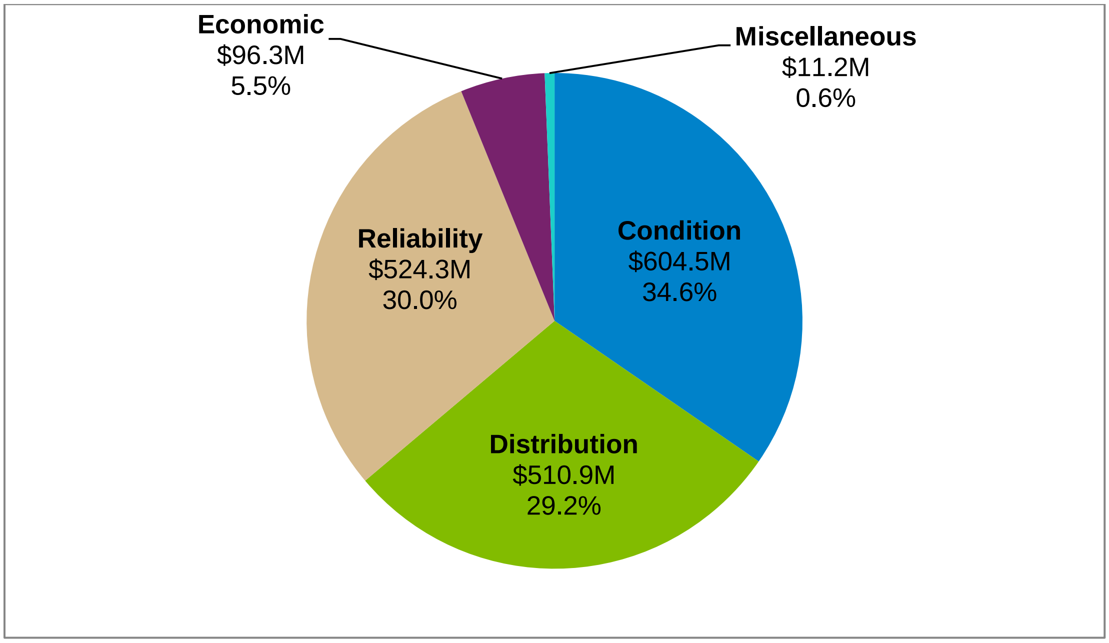


Figure 2.1-2: Subtype breakdown of new MTEP16 Appendix A Other projects

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, 52 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. 28 percent of MTEP costs go toward line upgrades including rebuilds, conversions and relocations. Only about 20 percent of facility cost is dedicated to new lines on new right-of-way across the MISO footprint.

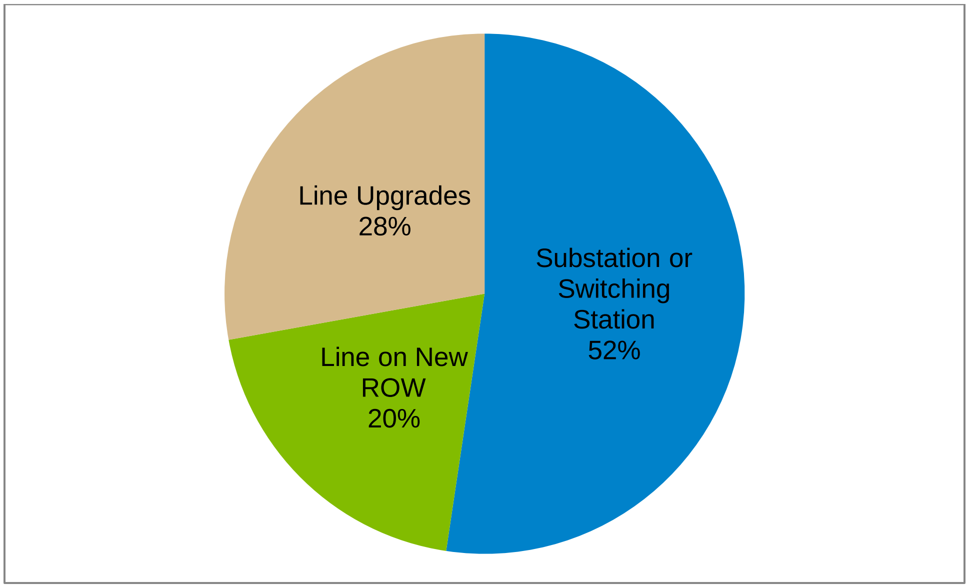


Figure 2.1-3: Facility type for new MTEP16 Appendix A projects

New Appendix A projects are spread over 13 states, with eight states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing capacity in other parts of the system is consumed and new build becomes necessary.

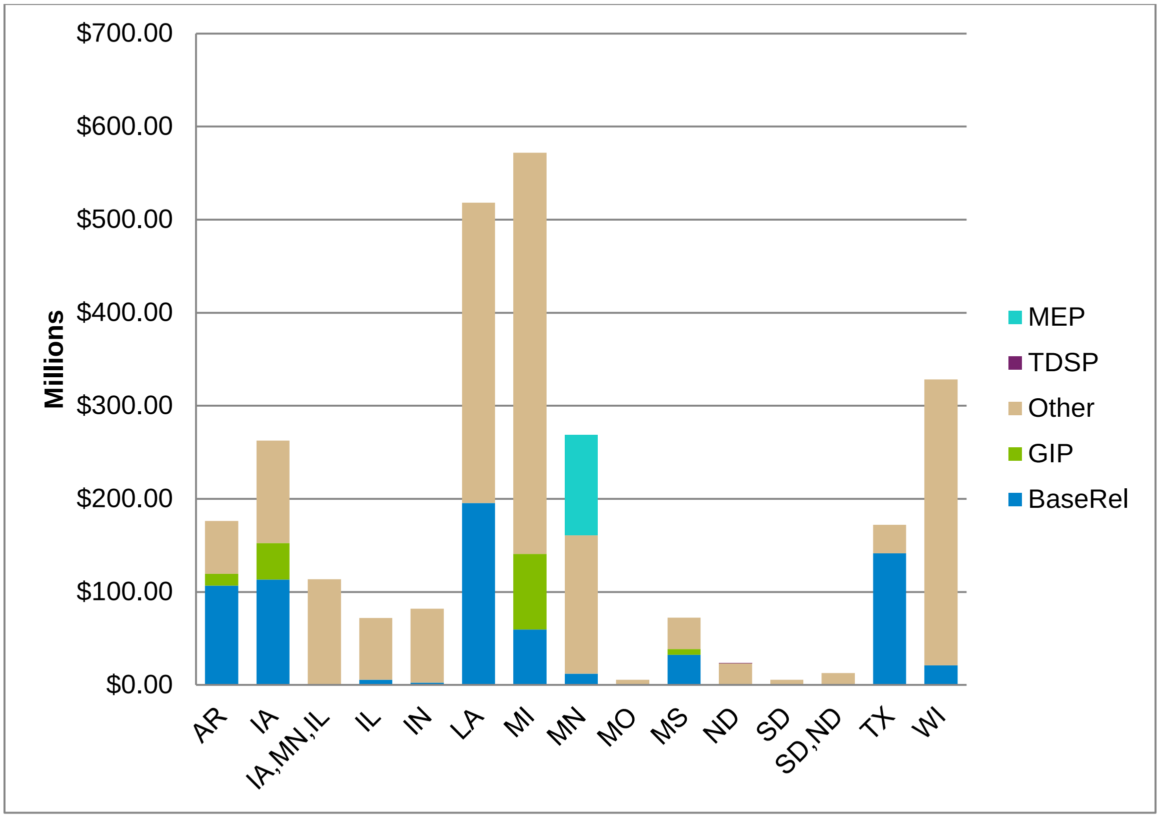


Figure 2.1-4: New MTEP16 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP16 new projects, increases to 964 projects amounting to approximately $13.3 billion of investment (Figure 2.1-5). MTEP16 Appendix A contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Large project investment is shown in a single year but often occurs over multiple years (Figure 2.1-6). Investment totals by year assume that 100 percent of a project's investment is fulfilled when the facility goes into service. It does not reflect projected cash flow or the fact that certain components of a project may be placed in service as a project progresses.

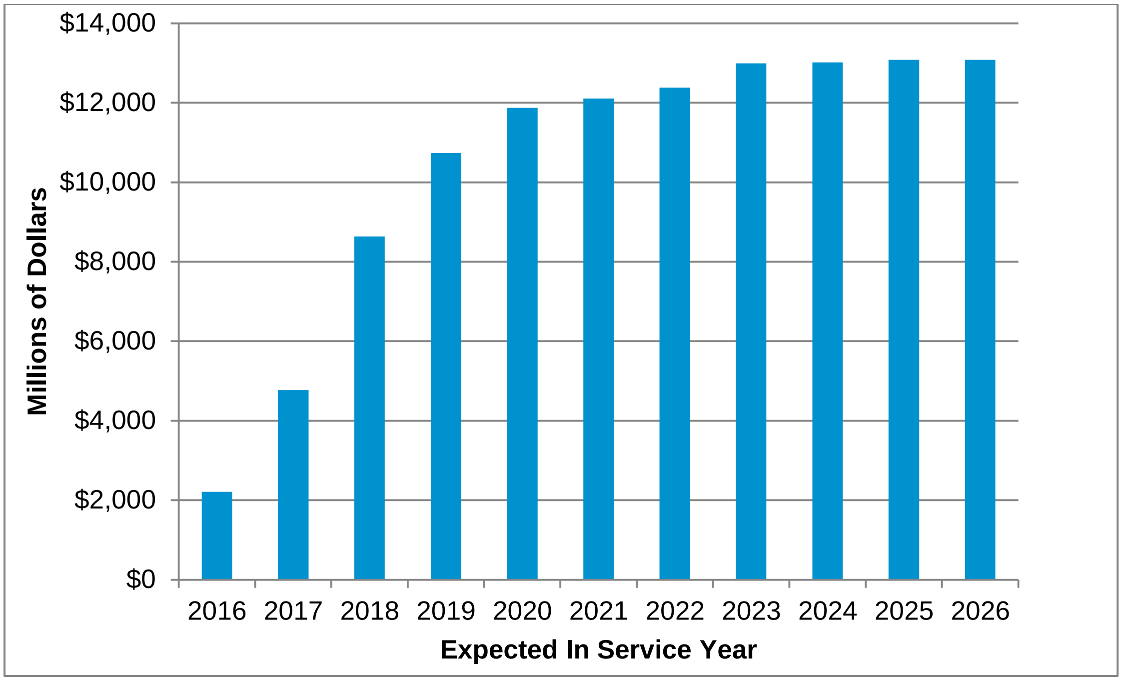


Figure 2.1-5: MTEP16 Appendix A projected cumulative investment by year

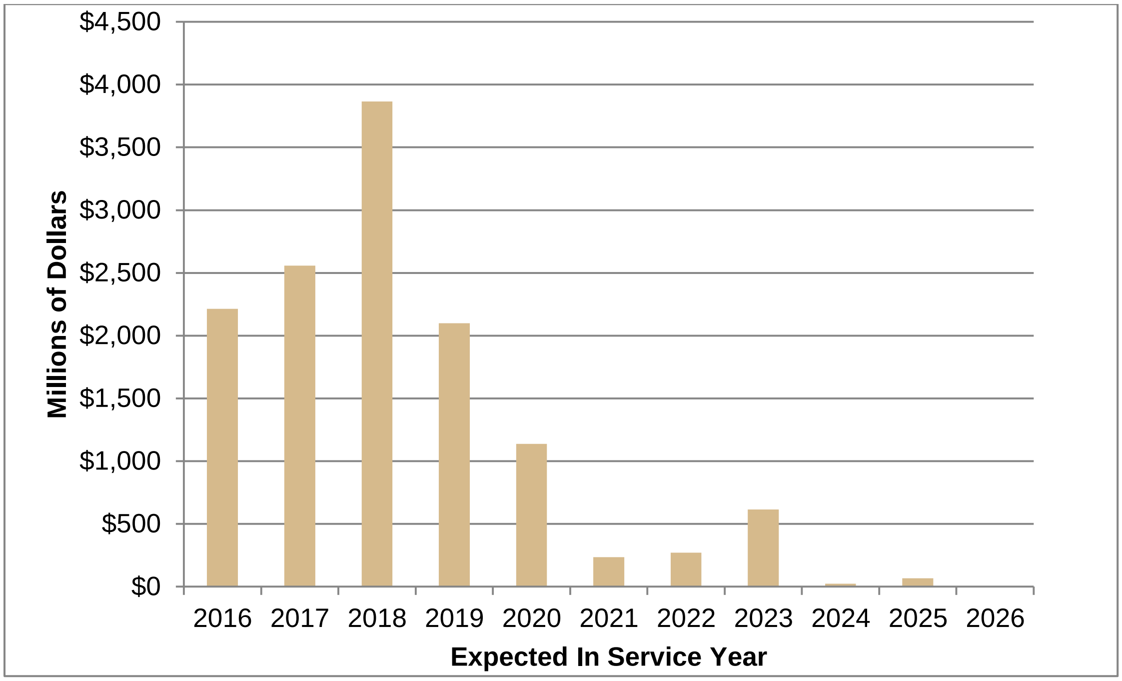


Figure 2.1-6: MTEP16 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[15] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $13.3 billion with another $3.0 billion in Appendix B. New MTEP16 Appendix A projects represents $2.69 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $5.1 billion of the $13.3 billion in cumulative Appendix A is from the Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the four MISO geographic planning regions: East, Central, West and South (Figure 2.1-7).

MISO Region	Number of Appendix A Projects	Appendix A Estimated Cost	Number of Appendix B Projects	Appendix B Estimated Cost
Central	170	$2,783,670,000	69	$132,807,000
East	219	$1,848,890,000	46	$579,008,000
West	387	$6,616,663,000	90	$1,754,715,000
South	188	$2,027,862,000	46	$505,244,000
Total	**964**	**$13,277,085,000**	**251**	**$2,971,774,000**

Table 2.1-2: Projected transmission investment by planning region

Figure 2.1-7: MISO footprint and planning regions

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

Active Appendix A Line Miles Summary

MISO has approximately 67,600 miles of existing transmission lines. There are approximately 7,100 miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in MTEP16 Appendix A (Figure 2.1-8, Table 2.1-3).

- 4,300 miles of upgraded transmission line on existing corridors are planned
- 2,800 miles of new transmission line on new corridors are planned

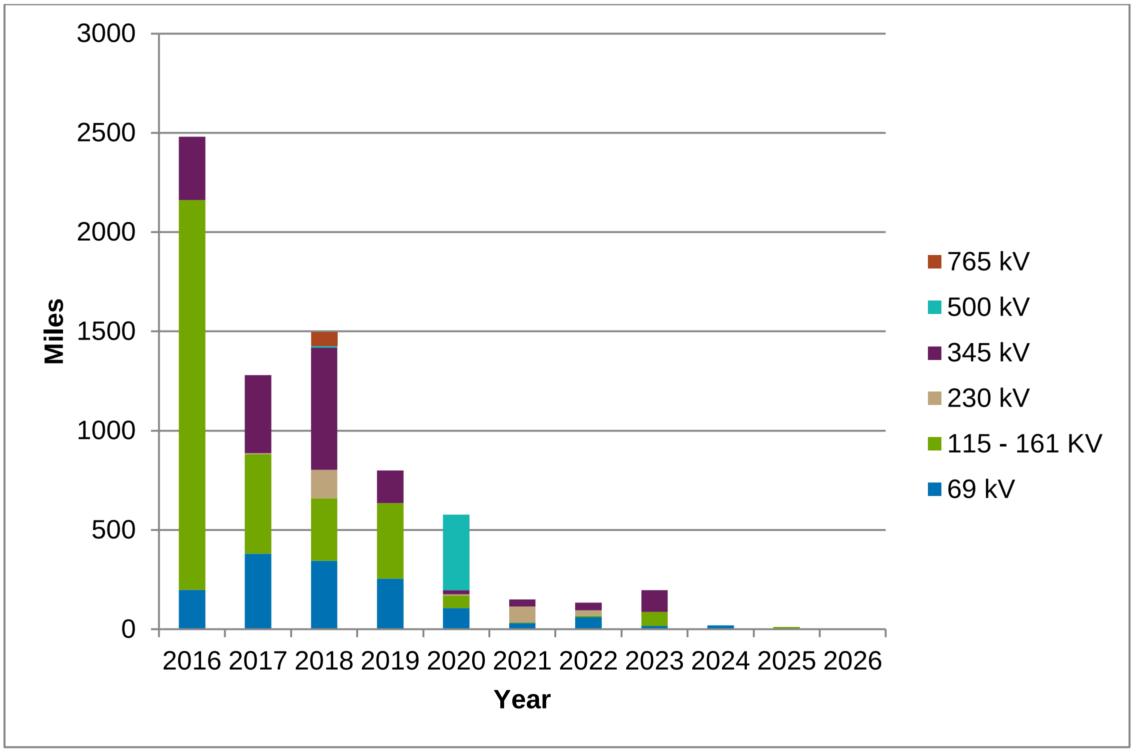


Figure 2.1-8: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2026

Year	69 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2016	199	1963	0	320	0	0	**2,481**
2017	381	500	6	393	0	0	**1,280**
2018	344	316	143	616	7	69	**1,495**
2019	255	381	0	165	0	0	**800**
2020	107	62	8	20	380	0	**577**
2021	32	2	81	35	0	0	**150**
2022	62	6	27	39	0	0	**134**
2023	17	71	0	109	0	0	**197**
2024	20	0	0	0	0	0	**20**
2025	3	8	0	0	0	0	**11**
2026	0	0	0	0	0	0	**0**
Grand Total	**1,419**	**3,309**	**264**	**1,696**	**387**	**69**	**7,145**

Table 2.1-3: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2026

2.2 Cost Sharing Summary

New MTEP16 Appendix A Cost-Shared Projects

MTEP16 recommends a total of 13 new cost-shared projects, with a total project cost of $183.5 million for inclusion in Appendix A. The 11 cost-shared projects include:

- 12 Generator Interconnection Projects (GIP) with a total project cost of $71.8 million, with $31.2 million allocated to load and the remaining $44.3 million allocated directly to generators[16]
- One Market Efficiency Project (MEP) with a total project cost of $108 million

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

Cost Allocation Between Planning Areas For GIPs and MEPs

With the integration of the MISO South region on December 19, 2013, a cost allocation transition period started that determines how approved cost-allocated projects are shared amongst the pricing zones in the MISO North/Central and MISO South planning areas. The transition period concludes when certain Tariff criteria are met, likely at the end of MTEP18.[17] The cost-shared projects in MTEP16 all terminate exclusively in the MISO North/Central planning area, and are cost shared amongst the MISO North/Central planning area pricing zones (Table 2.2-1).

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

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

[16] Note that the $44.3 million value 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.

[17] According to the Tariff: ***Second Planning Area's Transition Period:*** The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period.

Cumulative Summary of All Cost-Shared Projects Since MTEP06

A total of 170 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[18] (BRP) and GIPs, and was later augmented with MEPs in 2007 and Multi-Value Projects (MVP) in 2010. Starting with MTEP13 and going forward, the costs for BRPs were removed from cost sharing and allocated to the pricing zone of the project location. The cost-shared projects represent $10.0 billion in transmission investment, excluding projects that have been subsequently withdrawn or had a portion of project costs allocated directly to generators for GIPs (Figure 2.2-1, Table 2.2-2). The distribution of cost-shared projects includes:

- Baseline Reliability Projects (BRP) — 75 projects, $3.118 billion
- Generation Interconnection Projects (GIP) — 76 projects, $237 million (excluding the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — four projects, $186 million
- Multi-Value Projects (MVP) — 17 projects, $6.530 billion

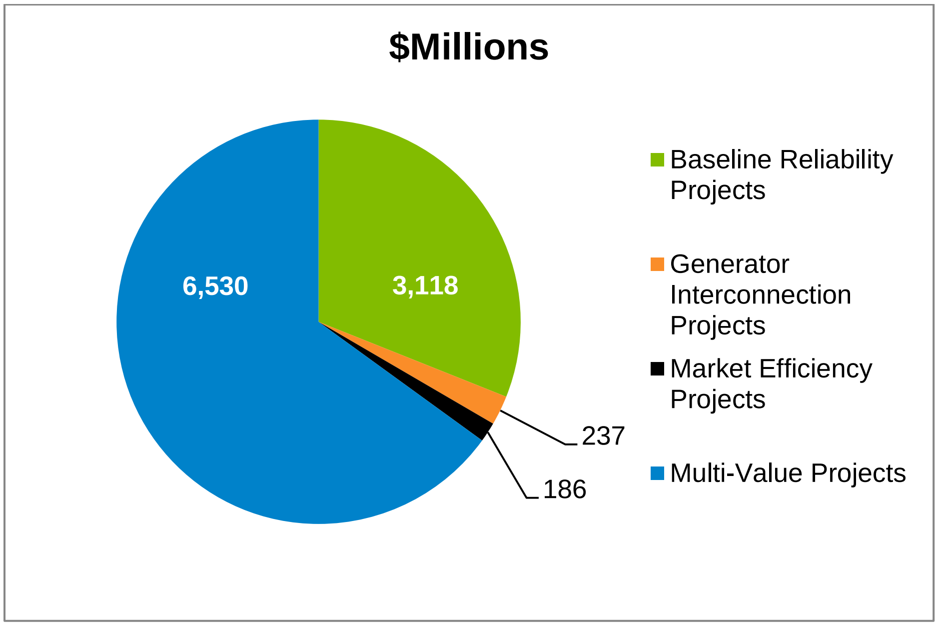


Figure 2.2-1: MTEP cumulative cost sharing by project type ($ millions)

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

Cost-Shared Project Type	BRP ($M)	GIP ($M)	MEP ($M)	MVP ($M)	Total ($M)
A in MTEP06	$672.8	$16.0	-	-	**$688.8**
A in MTEP07	$86.1	$16.6	-	-	**$102.7**
A in MTEP08	$1,288.0	$11.8	-	-	**$1,299.8**
A in MTEP09	$168.1	$64.1	$5.6	-	**$237.8**
A in MTEP10	$43.7	$1.2	-	$510.0	**$554.9**
A in MTEP11	$380.9	$46.6	-	$6,019.6	**$6,447.1**
A in MTEP12	$478.4	$26.3	$5.3	-	**$510.0**
A in MTEP13	-	$3.0	-	-	**$3.0**
A in MTEP14	-	$15.0	-	-	**$15.0**
A in MTEP15	-	$2.0	$67.4	-	**$69.4**
A in MTEP16	-	$31.2	$108	-	**$138.9**
Total	**$3,118.0**	**$233.8**	**$186.3**	**$6,529.6**	**$10,067.7**

Table 2.2-2: MTEP06 to MTEP16 cost-shared project costs by MTEP cycle and project type (shown in $ millions)

Cost allocation methods vary depending on the classification of the project. BRPs, and GIPs are not subject to the competitive bid process; the majority of the costs are allocated to the pricing zone where the project is located.[19] Of the $3.5 billion in approved costs for these project types (not including MVPs), approximately 65.2 percent ($2.3 billion) is allocated to the pricing zone where the project is located. The remaining 34.8 percent ($1.2 billion) is allocated to neighboring pricing zones or to all pricing zones system-wide within the North/Central planning areas. Appendix A-2.3 shows a tabular summary of this information by Transmission Pricing Zone.

Approximately 65.2 percent ($2.3 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located. The remaining 34.8 percent ($1.2 billion) is allocated to neighboring pricing zones or system-wide to all MISO North/Central planning area pricing zones

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

For the approved portfolio of MVPs, the costs are allocated 100 percent region-wide 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.

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.72 per month over the next 20 years

Indicative annual MVP Usage Rates[20] (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 2017 to 2056 and are shown by the blue line (Figure 2.2-2).[21] 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 $1.72 per month over the next 20 years.

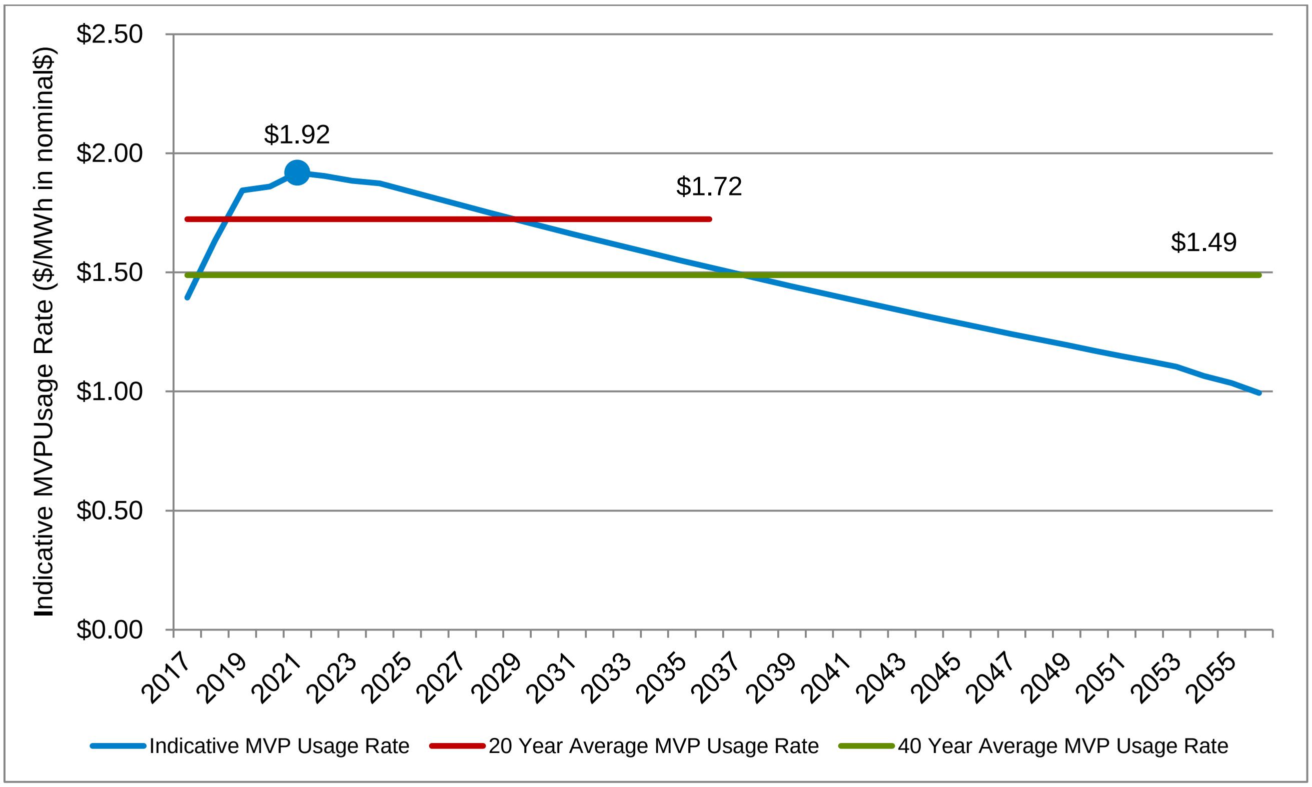


Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2017 to 2056

[20] 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.

[21] The annual estimated MVP Usage Rates for 2017 to 2056 shown in Figure 2.2-2 are included in Appendix A-3. Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO website at the following URL under the MTEP Study information section: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

2.3 MTEP16 Process and Schedule

MTEP joins together individual pieces of the transmission puzzle to create a comprehensive plan for expansion. At its most basic level MTEP is MISO's annual process to study and recommend transmission expansion projects for inclusion in MTEP Appendix A. Official approval of this report and its list of transmission projects occurs, if justified, at MISO's December 2016 Board of Directors meeting.

The process to produce the list of Appendix A projects requires 18 months of model building, stakeholder input, reliability analysis, economic analysis, resource assessments and report writing. It requires many hand-offs between various work streams and stakeholders (Figure 2.3-1). Along the way, the process includes sub-deliverables such as Planning Reserve Margins, resource forecasts, regional policy studies and interregional studies.

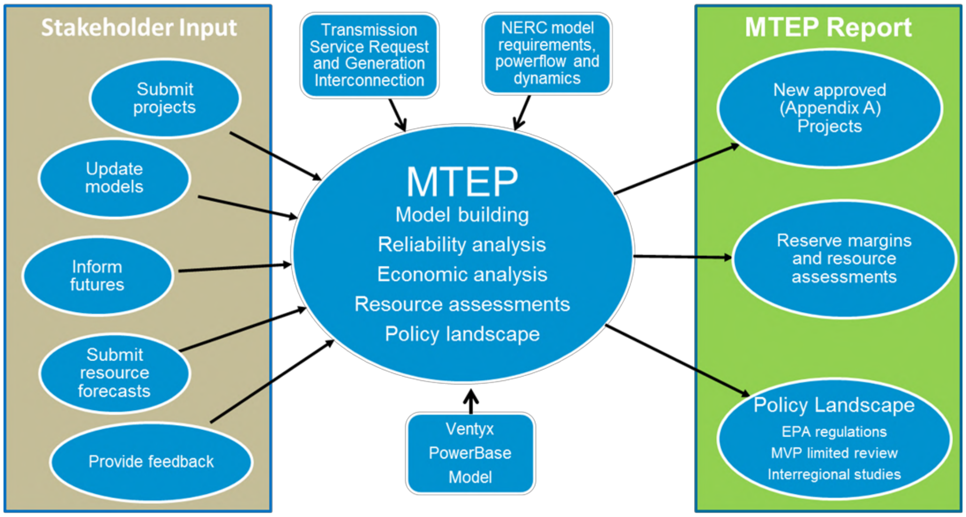


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

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

Figure 2.3-2: MISO Value-Based Planning Approach

MTEP16 Workstreams

Completion of MTEP16 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.

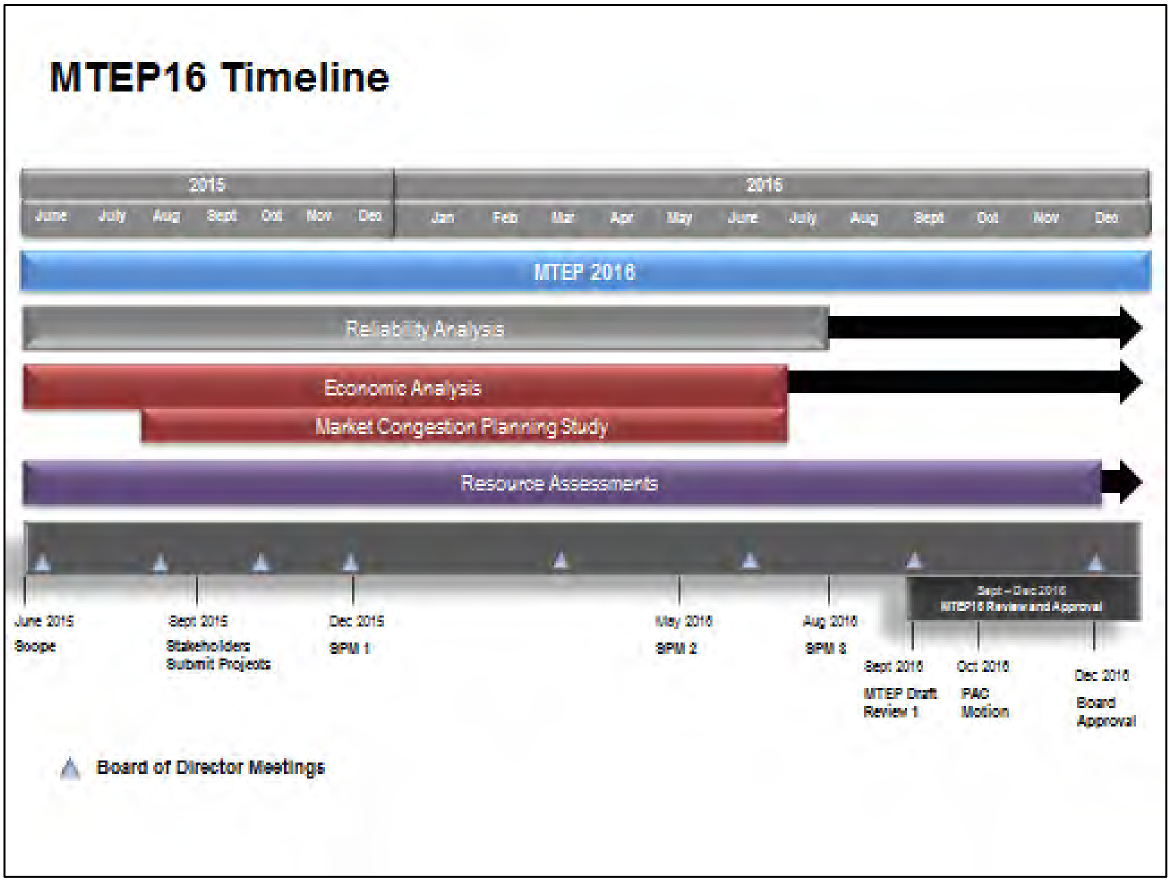


Figure 2.3-3: MTEP16 Timeline

Stakeholder Involvement in MTEP16

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

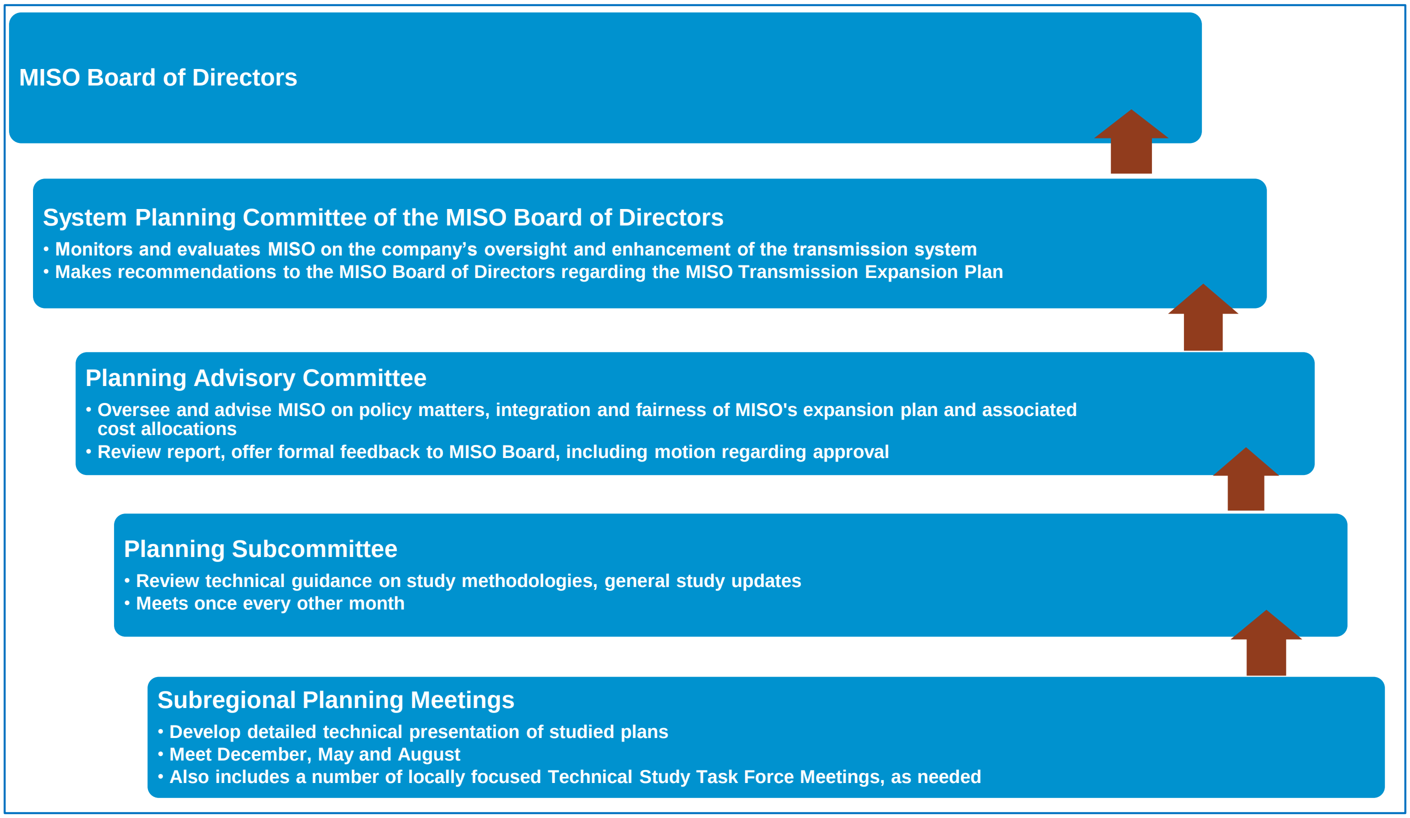


Figure 2.3-4: MTEP stakeholder forums

MTEP16 Schedule

Each MTEP cycle spans 18 months. MTEP16 began June 2015 and ends December 2016, with Board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP16 projects	September 2015
First round of Subregional Planning Meetings (SPM)	December 2015
Second round of Subregional Planning Meetings (SPM)	May 2016
MTEP16 Report first draft posted	August 2016
Third round of SPM meetings (8/15 to 8/25)	August 2016
Planning Advisory Committee final review and motion	October 2016
MISO Board System Planning Committee review	November 2016
MISO Board of Directors meeting to consider MTEP16 approval	December 2016

Table 2.3-1: MTEP16 schedule, major milestones

A Guide to MTEP Report Outputs

The MTEP16 report is organized into four books and a series of detailed appendices.

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

2.4 MTEP Project Types and Appendix Overview

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

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

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

Appendix A includes projects from prior MTEPs that are not yet in service, as well as new projects recommended to the MISO Board of Directors for approval in this cycle. Find the newest projects in the Appendix A spreadsheet by looking for "A in MTEP16" in the "Target Appendix" field.

There are three distinct categories of transmission projects:

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

The specific types of transmission projects include:

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

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

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

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

Bottom-Up Projects

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

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

Top-Down Projects

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

- **Multi-Value Projects (MVP)** meets 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 maximize benefit-to-cost ratios.

Externally Driven Projects

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

- **Generation Interconnection Projects (GIP)** are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all network upgrades associated with GIPs are eligible for cost sharing between pricing zones.
- **Transmission Delivery Service Project (TDSP)** projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.

- **Market Participant Funded Projects** represent transmission projects that provide benefits to one or more market participants but do not qualify as Baseline Reliability Projects, Market Efficiency Projects or Multi-Value Projects. These projects are not cost shared through the MISO Tariff. Their construction is assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Transmission Owners Agreement upon execution of the applicable agreement(s).

MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by MISO staff and approved by the MISO Board of Directors for implementation by Transmission Owners.[22]

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[23]. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards, while others may be required to provide distribution interconnections for load-serving entities. Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also decrease resource adequacy requirements through reduced losses during system peak or reduced planning reserve needs. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency standards. All projects in Appendix A address one or more MISO-documented transmission needs. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

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

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

[22] 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.
[23] http://www.nerc.net/standardsreports/standardssummary.aspx

MTEP Appendix B

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

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead time and there is still some uncertainty around the project drivers (such as changes in the projected conditions) or potential alternatives are still being considered.

MTEP Appendix B is limited to bottom-up projects only (Baseline Reliability Projects and Other Projects) and the projects will be reviewed by MISO in subsequent cycles to ensure the system needs still exist or a preferred solution is identified.

2.5 MTEP16 Model Development

Changes in the MTEP16 model-building process include data submission role additions per MOD-032-1 standard models

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

The MTEP16 model development process underwent some changes in data submission obligations per MOD-032-1 standard with inclusion of generator owners and load serving entities. In addition to TPL-001-4 standard requirements, MISO built a powerflow and dynamics model suite to support the Eastern Interconnection modeling process per MOD-032 requirements. Similar to MTEP15, there were two sets of models built. One model set contained approved future projects from MTEP15 Appendix A, and the other model set contained approved MTEP15 Appendix A projects and projects targeted for approval in MTEP16.

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

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

MTEP models are interdependent (Figure 2.5-1).

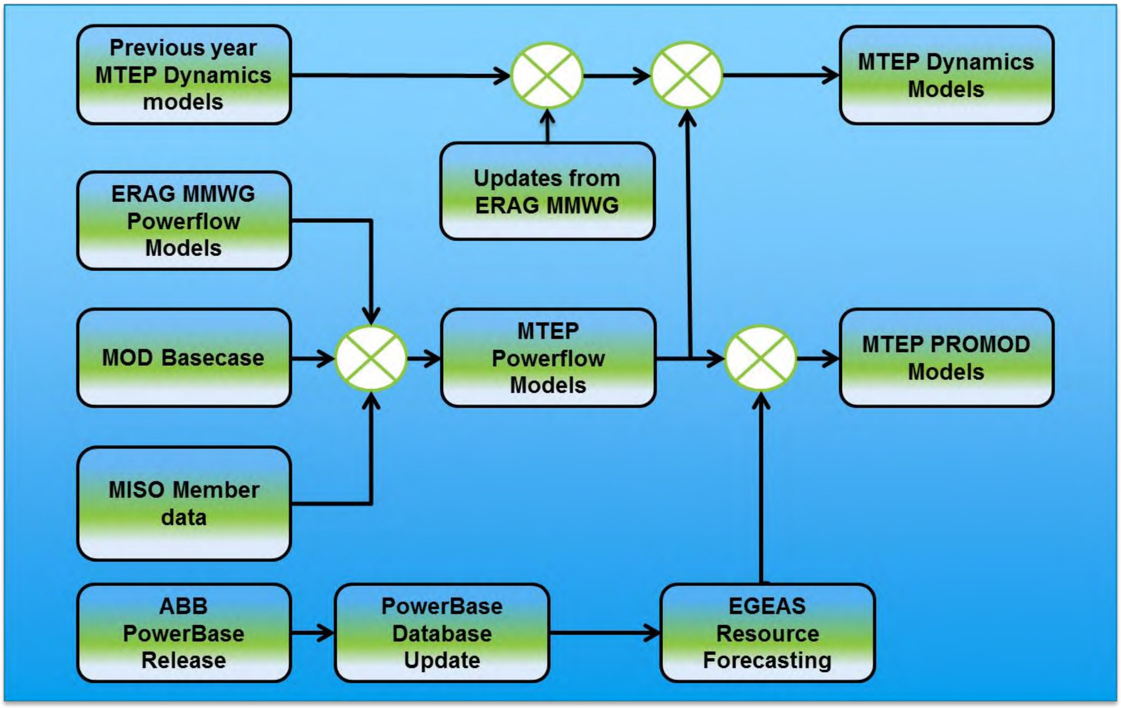


Figure 2.5-1: MTEP16 model relationships

Reliability Study Models

Powerflow Models

MISO developed regional powerflow models for MTEP16 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 corresponding TPL-001-4 requirement.

Model Year	Base case	Sensitivity
Year 2	2018 Summer Peak with wind at 15.6% (TPL requirement R2.1.1)	2018 Light Load (minimum load level) wind at 0% (TPL requirement R2.1.4)
Year 5	2021 Summer Peak with wind at 15.6% (TPL requirement R2.1.1)	2021 Summer Shoulder (70-85% peak) with wind at 90% (TPL requirement R2.1.4)
Year 5	2021 Summer Shoulder (70-85% peak) with wind at 40% (TPL requirement R2.1.2)	2021 Light Load (minimum load level) with wind up to 90% (TPL requirement R2.1.4)
Year 5	2021-2022 Winter Peak (Wind at 30%)	
Year 10	2026 Summer Peak (Wind at 15.6%) (TPL requirement R2.2.1.)	

Table 2.5-1: MTEP16 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 is updated monthly in collaboration with MISO members.
- R1.1.2. Known Outages: MISO models any known outage(s) of generation or transmission facility with a duration of at least six months using data from Control Room Operations Window (CROW) Outage Scheduling System and publicly known information.
- 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 date. To support MTEP study requirements, two sets of powerflow models were developed:
    - MTEP15 Appendix A, which includes only approved future transmission facilities first approved in MTEP15 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.
    - MTEP15 Appendix A plus MTEP16 Target Appendix A: This includes future transmission projects approved in Appendix A through prior MTEP studies and new transmission projects submitted for approval in the MTEP16 planning cycle to verify their need and sufficiency in ensuring system reliability
- R1.1.4. Real and reactive Load forecasts: real and reactive load is modeled based on seasonal load projections provided by member companies to the MISO MOD.
- R1.1.5. Known commitments for Firm Transmission Service and Interchange: MISO models known commitments based on the information obtained from the transacting parties.
- R1.1.6. Resources (supply or demand side) required for Load: Resources are modeled based on seasonal projections submitted by members in MOD. All the existing generators are included. Planned generators with signed Generation Interconnection Agreements are included according to their expected in-service dates. Generator retirements that have completed the MISO Attachment Y retirement study process are modeled off-line when unit can be retired.

LBA Generation Dispatch Methodology

The generation dispatch in steady-state powerflow models is done at the Local Balancing Area (LBA) level. Network Resource-type generation is dispatched in an economic order to meet the load, loss and interchange level for each LBA. The area interchange for each LBA is determined by the transaction table agreed upon by transaction participants, and the generation is dispatched to account for the cumulative MISO net area interchange level. Network Resource dispatch includes some energy resources, such as wind, which is 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. 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
- 30 percent represents the wind output level in the winter model

The input of LBA dispatch is the generation and load profile data submitted by members in the MOD system. Output of generators is determined considering 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. Energy resources are not dispatched, with the exception of wind resources.

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 Model On Demand system for inclusion in subsequent versions of the models.

Generation, load and area interchange data is calculated for each MISO control area for 2018 summer and 2021 summer peak models (Table 2.5-2). Note that there may be differences in the load values for each area from the Module E load values due to inclusion of station service loads and non-member loads contained within the MISO members' model control areas.

Area	2018SummerPeak (All numbers in MW)				2021SummerPeak (All numbers in MW)			
	GEN	Load	Losses	Area Interchange	GEN	Load	Losses	Area Interchange
HE	1,366	572	30	764	1,422	579	30	813
DEI	6,999	7,556	319	(882)	7,072	7,689	314	(937)
SIGE	1,917	1,952	27	(61)	1,965	1,949	25	(9)
IPL	3,353	3,100	83	166	3,351	3,010	81	257
NIPS	3,853	3,548	53	246	3,853	3,612	56	179
METC	11,344	10,215	349	780	11,473	10,307	351	814
ITCT	10,984	11,523	249	(788)	10,941	11,509	254	(822)
WEC	6,720	6,421	97	189	6,803	6,521	98	171
MIUP	535	615	23	(105)	537	621	22	(108)
BREC	1,544	1,596	16	(68)	1,610	1,614	17	(21)
EES-EMI	4,133	4,010	110	7	4,137	4,028	105	(3)
EES-EAI	9,413	7,745	173	1,493	9,083	7,883	158	1,040
LAGN	3,043	1,734	13	1,296	3,037	1,867	12	1,159
CWLD	234	389	2	(157)	251	406	2	(157)
SMEPA	1,294	851	21	422	1,339	881	20	438
EES	17,460	18,959	355	(1,858)	17,594	19,397	353	(2,161)
AMMO	8,630	7,942	187	500	8,740	7,917	190	633
AMIL	11,049	9,764	262	1,024	11,043	9,829	255	958
CWLP	721	489	4	228	686	482	3	201
SIPC	361	345	14	2	383	360	14	9
CLEC	3,633	3,062	72	499	3,724	3,166	66	493
LAFA	252	497	7	(252)	278	523	7	(252)
LEPA	-	229	0.1	(230)	6	240	0.1	(235)
XEL	9,601	10,538	246	(1,201)	9,631	10,743	227	(1,357)
MP	1,577	1,668	42	(135)	1,519	1,687	64	(234)
SMMPA	115	605	1	(492)	127	617	1	(492)
GRE	2,663	2,845	92	(277)	2,520	2,865	92	(440)
OTP	2,149	1,751	78	318	2,173	1,818	81	272

Area	2018SummerPeak (All numbers in MW)				2021SummerPeak (All numbers in MW)			
	GEN	Load	Losses	Area Interchange	GEN	Load	Losses	Area Interchange
ALTW	4,193	4,013	93	87	4,211	4,018	90	102
MPW	219	162	1	55	194	165	1	28
MEC	6,008	6,147	97	(237)	6,004	6,297	97	(391)
MDU	439	665	12	(238)	445	699	15	(269)
DPC	835	1,048	42	(255)	854	1,063	36	(245)
ALTE	3,634	2,865	76	688	3,712	2,957	76	674
WPS	2,167	2,634	53	(525)	2,180	2,651	50	(526)
MGE	381	767	10	(398)	349	785	10	(448)
UPPC	46	228	8	(190)	47	228	8	(190)
	142,859	**139,048**	**3,316**	**414**	**143,292**	**140,984**	**3,282**	**(1,056)**

Table 2.5-2: System conditions for 2018 and 2021 models, for each MISO control 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 5	2021 Summer Peak with wind at 15.6% (TPL requirement R2.4.1)	2021 Light Load (minimum load level) with wind up to 90% (TPL requirement R2.4.3)
Year 5	2021 Summer Shoulder (70-80% peak) with wind at 40% (TPL requirement R2.4.2)	2021 Summer Shoulder (70-80% peak) with wind at 90% (TPL requirement R2.4.3)

Table 2.5-3: MTEP16 dynamic stability models

The MTEP15 dynamics data is the starting point for MTEP16 dynamics model development. This data is reviewed and updated with stakeholder feedback. Additionally, the ERAG MMWG 2015 series dynamic stability models are reviewed and any improved modeling data in external areas is incorporated in the MTEP16 dynamics models.

Dynamic load modeling in MTEP16 dynamic models is driven by Requirement 2.4.1 of the TPL-001-4 standard. 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 identical to steady-state powerflow models.

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

Dynamic load models are a recent addition to stability models and improve model accuracy

During the MTEP16 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 MTEP16, the Planning Advisory Committee (PAC) approved the following future scenarios:[24]

- Business As Usual
- High Demand
- Low Demand
- Regional Clean Power Plant (CPP) Compliance
- Sub Regional CPP Compliance

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 extensive model development process that updates the source data provided by ABB with MISO-specific updates.

Updates include data obtained from the following sources:

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

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

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

The PowerBase database, including system topology, was posted for stakeholder review. 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 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).

Chapter 3

Historical MTEP Plan Status

2016

3.0 Historical MTEP Plan Status

Since the first MTEP report in 2003, more than $12.9 billion in projects have been constructed in the MISO region. Not including withdrawn projects, there are currently $10.6 billion of previously approved projects in various stages of design, planning or construction as of September 2016.

Chapter 3.1 presents a status update on the implementation of active projects approved in previous MTEP reports.

Chapter 3.2 provides a historical perspective of past MTEP approved plans.

3.1 MTEP15 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 MTEP15 Appendix A projects as of Quarter 1, 2016, 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

Since the first MTEP report in 2003, a total of $25.6 billion in transmission projects have been approved. Of this approved investment, $12.9 billion have been constructed; $2.1 billion has been withdrawn; and the remaining $10.6 billion is in various stages of design, planning or construction through the third quarter of 2016.

Following the approval of a MTEP, MISO continues to provide transparency through its publication of 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 summarized information regarding the status of previously approved MTEP Appendix A projects to present general trends and notable highlights. Since MTEP13, this information has been presented by summarizing the differences between the costs and schedules published in the respective MTEP reports from those costs and schedules provided to MISO by Transmission Owners and Selected Developers through their submitted status updates.

The cost and schedule trending analysis conducted on the projects approved in MTEP15 considers all active Appendix A projects that were not in service or otherwise withdrawn as of September 2016. Additionally, the MVPs are excluded from the trend analysis because of the significant amount of investment related to the MVPs approved in MTEP11 when compared to other projects included in Appendix A of a respective MTEP (Figures 3.1-1 and 3.1-2). This is addressed following the discussion on the non-MVP facilities (Figure 3.1-3).

Though this section focuses on projects that have experienced cost-increases or schedule delays, these projects do not represent the norm. The majority of MISO's previously approved projects have little to no deviations from the cost and schedules that were published in their respective MTEP reports.

The majority of projects have small or no deviations from the MTEP-approved costs and schedule.

As of the third quarter of 2016, MISO is tracking 565 active projects from MTEP15 Appendix A totaling $5.74 billion of approved investment. Of this total, 45 percent were approved in MTEP15 and the remaining 55 percent were approved in MTEP03 through MTEP14. All costs contained within this section are in nominal, as-spent dollars.

Non-MVP Project Cost Variation

The estimated total costs for the 565 active MTEP15 Appendix A projects have increased from the MTEP-approved $5.4 billion to $5.7 billion, a cost variance of 6 percent. Costs can vary for multiple reasons. At the time of board approval, a project cost estimate reflects:

- Rough line routing and station costs
- Estimated labor and materials
- Known environmental concerns
- Contingency allowance

At project completion, after regulatory issues have been addressed and uncertainties eliminated, a project's updated cost reflects:

- Final line routing and costs
- Actual commodity and labor costs
- Total environmental mitigation costs

Overall, the number of projects with significant cost increases (with respect to the project size and scope) is small. The projects with the largest percentage deviation were generally projects with a small total cost. Currently, 85 percent of projects have increased by less than 25 percent of their original cost estimate; 68 percent of projects have no reported cost increase or have a decreased cost estimate.

The cost-shared projects of the MTEP15 Appendix A subset represent $680 million in approved MTEP investment. Of the 12 active (non-MVP) cost-shared projects, five projects' cost estimates have not increased since approval and only one projects' costs currently expected to increase by more than 25 percent of the original estimate. All projects with cost deviations are Baseline Reliability Projects or Generator Interconnection Projects, which are not justified based on economics (red line, Figure 3.1-1). The cost-shared trend has decreased over the last two quarters as projects go into service and the number of active cost-shared projects decreases. Also, fewer cost shared projects are approved each cycle due to a change in cost sharing methodology after MTEP13.

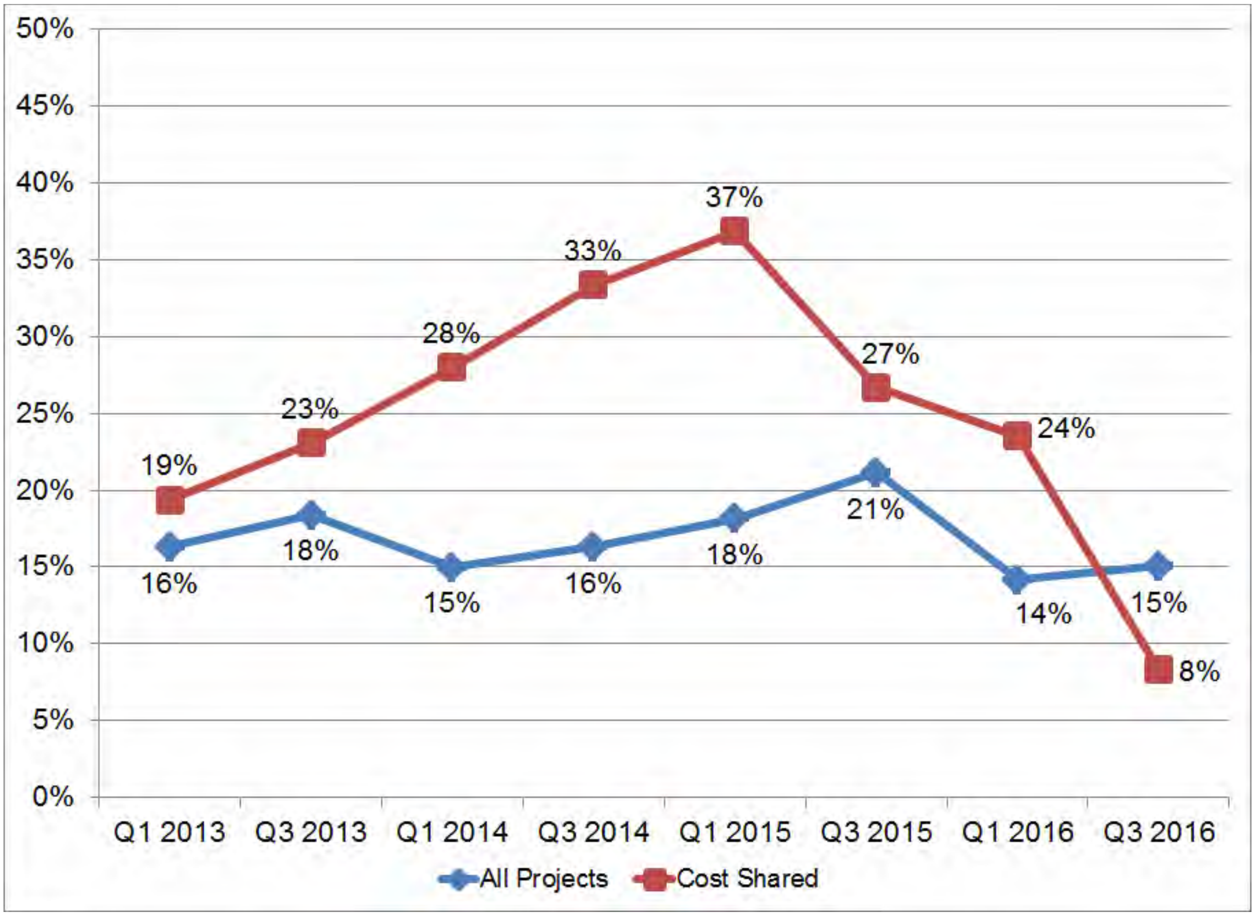


Figure 3.1-1: Percentage of active MTEP15 Appendix A Projects (non-MVP) that have deviated by more than 25 percent of their original cost estimate, through Q3 2016

Non-MVP Project Schedule Variation

The 565 MTEP15 Appendix A projects have, on average, delayed their in-service date by 14 months. Little or no impact on reliability is expected from the adjusted in-service dates. Transmission Owners may adjust project in-service dates to match system needs. Common drivers of schedule variance include:

- Budgetary constraints
- Weather
- Length of regulatory process
- Equipment or material delays
- Time required to secure property rights
- Changes in design resulting from routing changes

The expected in-service date of 39 percent of Active MTEP15 Appendix A projects have not extended beyond the MTEP-approved estimate. Projected in-service dates have extended beyond 12 months for 43 percent of the Active MTEP15 Appendix A projects (blue line, Figure 3.1-2).

The current expected in-service date has been extended by more than 12 months from the MTEP approval for eight of the 12 cost-shared MTEP15 Appendix A projects (red line, Figure 3.1-2).

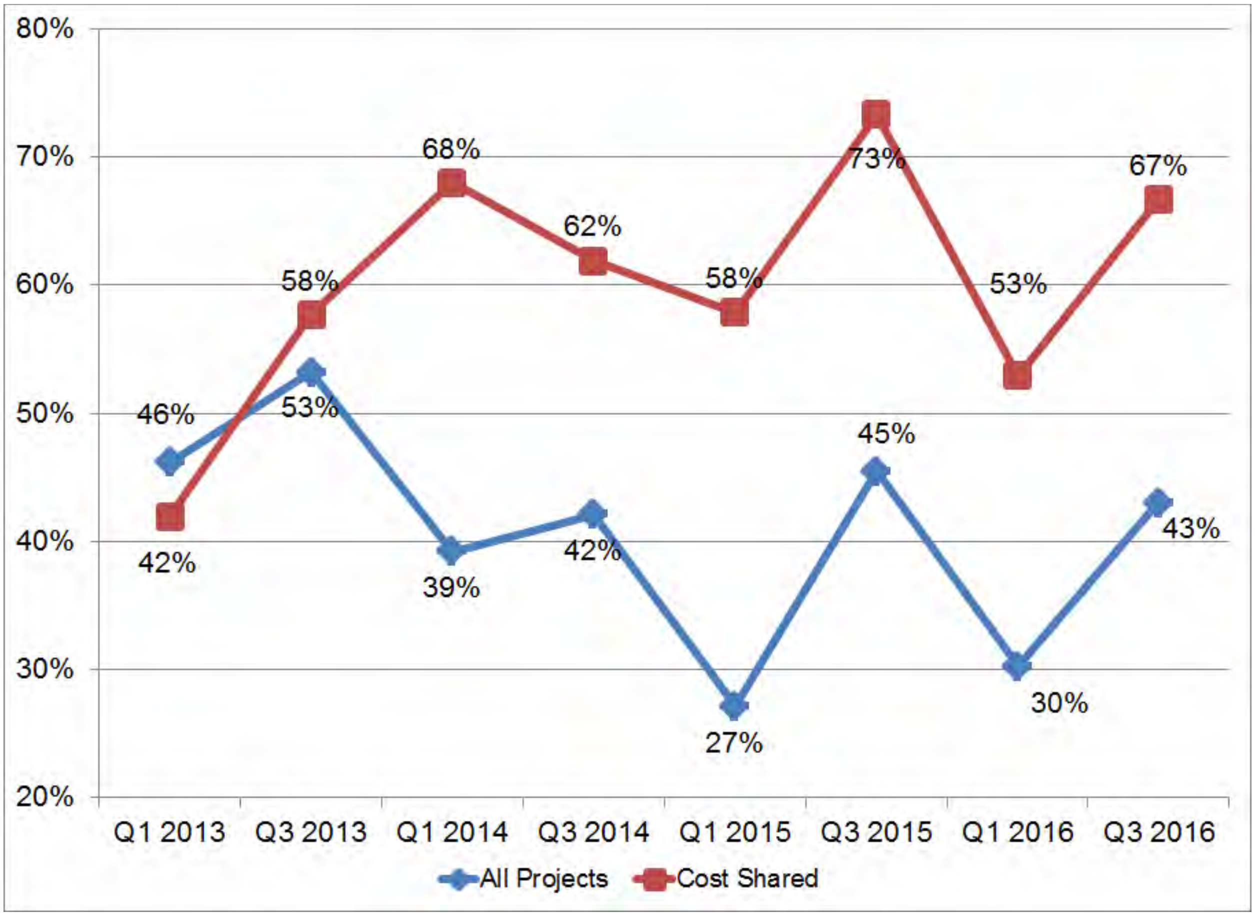


Figure 3.1-2: Percentage of active MTEP15 Appendix A Projects (non-MVP) that have a schedule delay of more than 12 months from the original expected in service date, through Q3 2016

Multi-Value Project Portfolio Status

The MVPs are part of a regionally planned portfolio of transmission projects. The MVP portfolio represents the culmination of more than eight years of planning efforts to find cost-effective regional transmission solutions while meeting local energy and reliability needs. The MVP portfolio is expected to[25]:

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

The 17 MVPs are generally projected to meet budget and schedule expectations. As of September 2016, three projects are in service, six projects are at least partially under construction and the remainder are complete or are in progress with state regulatory approvals (Figure 3.1-3). Since the MTEP11 approval,

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

the total projected budget for the MVP Portfolio has increased by 18.8 percent, the result of longer-than-planned line routing, substation design changes and use of more developed construction estimates.

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

Multi-Value Project Status as of Q3 2016

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q2 2016	State Regulatory Status	Construction	MTEP Approved	Q2 2016
1	Big Stone-Brookings	SD	2017	2017	●	Pending	226.7	226.7
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	738.4	672.4
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	●	Underway	550.4	545.7
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	●	Underway	468.6	470.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project)	WI/IA	2018-2020	2018-2023	●	Pending	797.5	1046.1
	Cardinal-Hickory Creek	WI/IA	2018-2020	2018-2023	◑	Pending		
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Pending	330.7	395.7
7	Ottumwa-Zachary	IA/MO	2017-2020	2017-2018	◑	Pending	152.3	191.9
8	Zachary-Maywood	MO	2016-2018	2016-2018	◑	Pending	112.8	153.4
9	Maywood-Herleman-Meredosia-Ipava & Meredosia-Austin	MO/IL	2016-2017	2016-2017	●	Underway	432.2	705.4
10	Austin-Pana	IL	2018	2016-2018	●	Pending	99.4	135.5
11	Pana-Faraday-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2018	●	Underway	318.4	439.7
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Underway	271.0	388.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	387.5
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Sandburg-Oak Grove	IL	2014-2019	2016-2018	●	Pending	199.0	219.3
17	Sidney-Rising	IL	2016	2016	●	Underway	83.2	90.6
						Totals:	***5,564***	***6,611***

State Regualtory Status Indicator Scale

- ○ Pending
- ◑ In regulatory process or partially complete
- ● Regulatory process complete or no regulatory process requirements

1. Estimates provided by constructing Transmission Owners. Costs stated in millions of nominal dollars.

Figure 3.1-3: MVP Planning and Status Dashboard as of September 2016

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 MTEP16 cycle, the MTEP report now represents 13 years of planning these essential upgrades and expansions to the electric transmission grid.

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

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

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP16 cycle, is more than $26.2 billion (Figure 3.2-1). MTEP16 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.

- Since MTEP03, approximately $12.9 billion of cumulative approved projects have been constructed and are in service as of September 2016
- $3.1 billion of MTEP projects are expected to go into service in 2016

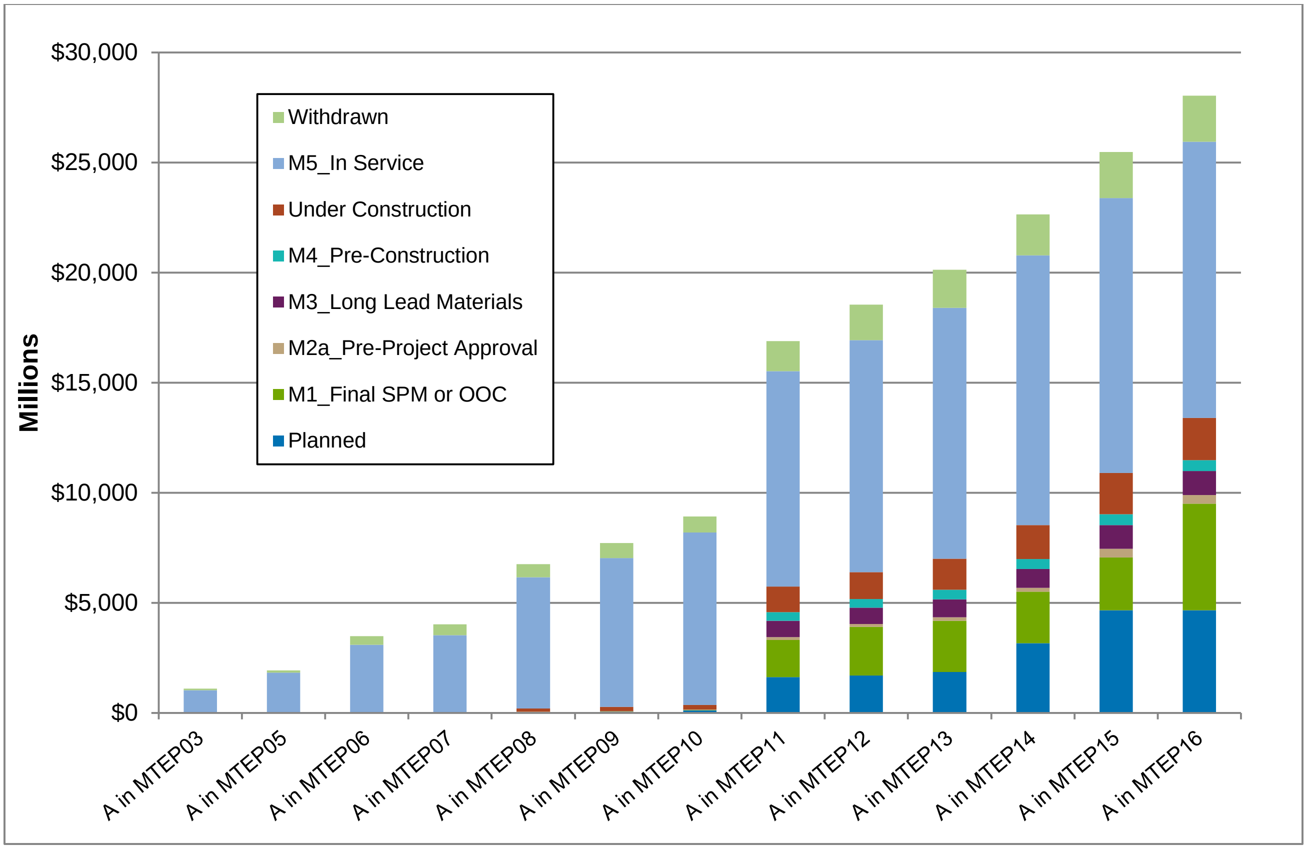


Figure 3.2-1: Cumulative Investment by Facility Status[26]

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

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small incremental value of projects in MTEP07.
- MTEP08 shows the number of developing needs increased the number of planned projects, including several large upgrades.
- MTEP09 was a year for analyses and determination of the best plans to serve those needs. The in-service category increases as projects are built.
- MTEP10 contains significant adjustments for reduced load forecasts.
- MTEP11 contains the MVP portfolio, which accounts for the significantly higher investment totals compared to other MTEPs. MVP status and investment totals are tracked via the MVP Dashboard.
- MTEP12 and MTEP13 reflect a return to a more typical MTEP, primarily driven by reliability projects.

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

- MTEP14 reflects a continuation of a typical MTEP, primarily driven by reliability projects, but with the inclusion of the new MISO South region projects. A single transmission delivery service project accounts for around 25 percent of the total MTEP14 investment.
- MTEP15 and 16 further reflect a continuation of a typical MTEP, primarily driven by reliability projects. Beginning in MTEP15, MTEP participants began planning to meet a series of new, more stringent NERC reliability standards.

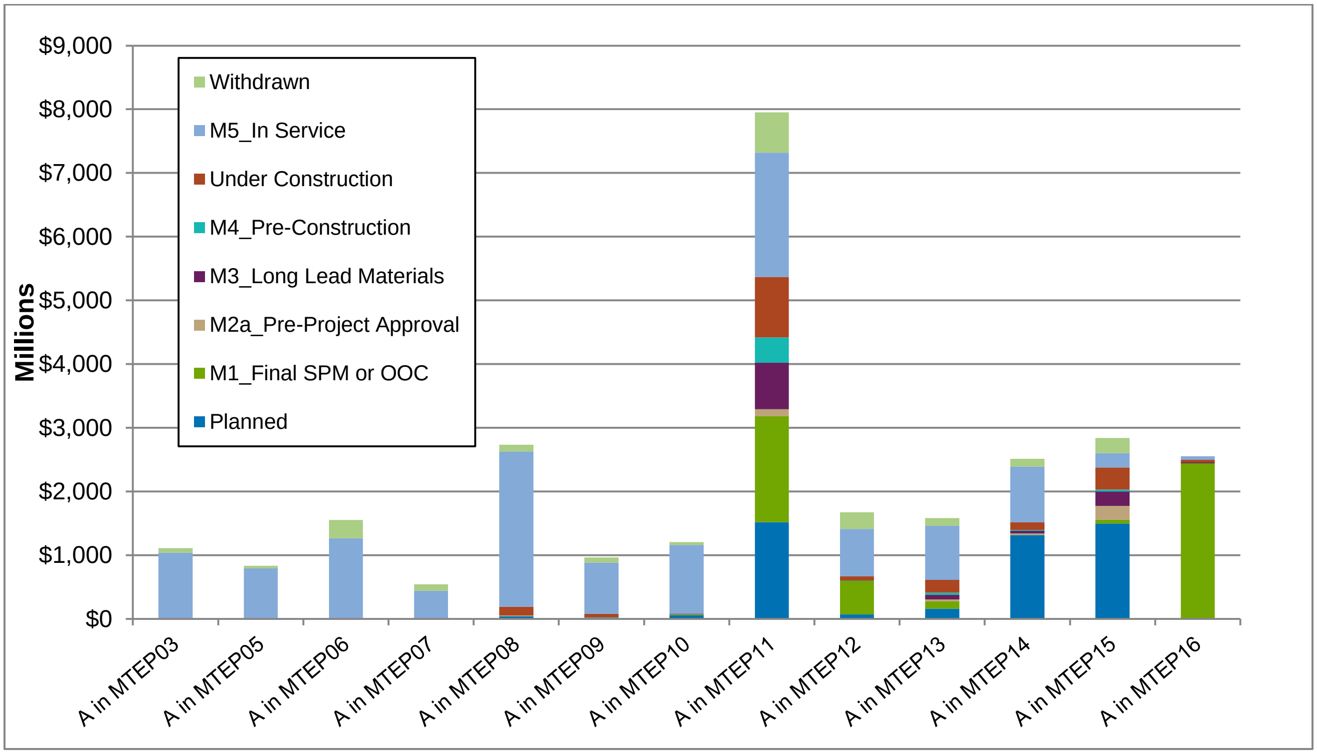


Figure 3.2-2: Approved Investment by MTEP Cycle[27]

Since MTEP03, approximately $2.1 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.

[27] New Appendix A projects in the MTEP16 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.

Chapter 4
Reliability Analysis

2016

4.1 Reliability Assessment and Compliance

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

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

The results of these reliability analyses, along with the proposed mitigating transmission projects, were presented and peer-reviewed at a series of Subregional Planning Meetings (SPM) that were held in December 2015, May-June 2016 and August 2016. Each project included in MTEP Appendix A is the preferred solution to a transmission need when its implementation timeline requires near-term progress towards regulatory approval and construction.

The details of the MTEP16 reliability assessment are summarized in this chapter and the complete results are presented in Appendix D of this MTEP16 report.

Process Overview

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

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

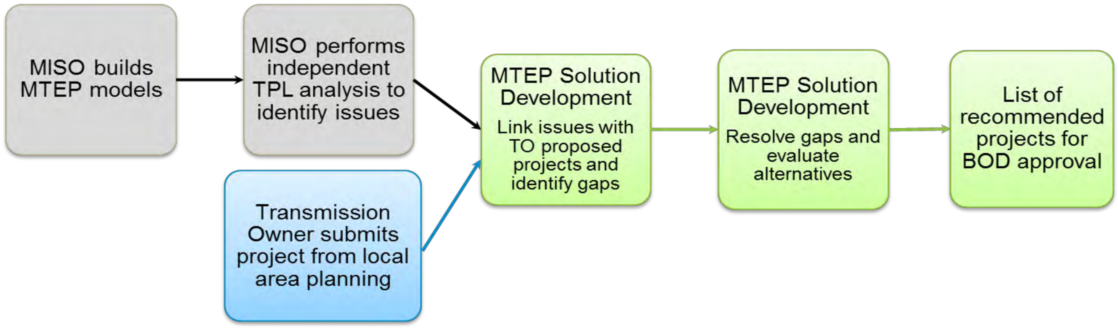


Figure 4.1-1: MTEP16 Reliability Study Process

Models

In MTEP16, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with our stakeholders:

- 2018 Summer Peak (wind at 14 percent)
- 2018 Light Load (wind at 0 percent)
- 2021 Summer Peak (wind at 14 percent)
- 2021 Shoulder Peak (wind at 40 percent)
- 2021 Shoulder Peak (wind at 90 percent)
- 2021 Light Load (wind at 90 percent)
- 2021 Winter Peak(wind at 30 percent)
- 2026 Summer Peak (wind at 14 percent)

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP16 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 2015 series Multiregional Modeling Working Group (MMWG) interchange.[28] MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

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

Inputs in the dispatching process include:

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

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

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 90 percent of nameplate in the shoulder cases. These wind dispatch levels were selected through the MISO planning stakeholder process. More information on the models may be found in Appendix D2 of this report.

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

NERC Reliability Assessment

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

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

Based on the NERC reliability assessment performed by MISO, potential thermal and voltage reliability issues are identified. MISO and its TOs are required to develop and implement solutions for each identified constraint. Violations are mitigated via system reconfiguration, generation redispatch, implementation of an operating guide, or with a transmission upgrade, as appropriate and consistent with the requirements of the applicable reliability standards. Identified transmission upgrades to future system issues are investigated further in subsequent MTEP cycles.

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

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance. The complete study is available in Appendices D2-D8 of this report, which is posted on the MISO SFTP site. 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 MTEP16 2018 summer peak and shoulder peak models; the 2021 summer peak, shoulder peak, winter peak and light-load models; and the 2026 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 MTEP16 2021 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 P-V 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 (blue), East (green), South (orange) and West (red).

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
20-Nov-15	South TSTF Meeting	Web-ex/conf. call
4-Dec-15	East SPM No. 1	Detroit, Mich.
8-Dec-15	South SPM No. 1 (Miss., La., Texas, Ark.)	Metairie, La.
10-Dec-15	West SPM No. 1	Eagan, Minn.
14-Dec-15	Central SPM No. 1	Carmel, Ind.
17-Dec-15	South TSTF Meeting	Web-ex/conf. call
6-Jan-16	East TSTF Meeting	Web-ex/conf. call
8-Feb-16	West TSTF Meeting	Web-ex/conf. call
19-Feb-16	West TSTF Meeting	Web-ex/conf. call
11-Mar-16	Central TSTF Meeting	Web-ex/conf. call
22-Mar-16	Central TSTF Meeting	Web-ex/conf. call
31-Mar-16	East and West TSTF Meeting (closed)	Livonia, Mich.
6-May-16	East TSTF Meeting	Web-ex/conf. call
24-May-16	East SPM No. 2	Livonia, Mich.
26-May-16	Central SPM No. 2	Carmel, Ind.
2-Jun-16	South SPM No. 2 (Miss., La., Texas, Ark.)	Metairie, La.
3-Jun-16	West SPM No. 2	Eagan, Minn.
28-Jul-16	Michigan TSTF Meeting (closed)	Web-ex/conf. call
15-Aug-16	Central SPM No. 3	Carmel, Ind.
22-Aug-16	West SPM No. 3	Eagan, Minn.
24-Aug-16	East SPM No. 3	Cadillac, Mich.
25-Aug-16	South SPM No. 3 (Miss., La., Texas, Ark.)	Little Rock, Ark.
29-Sept-16	Michigan TSTF Meeting (closed)	Web-ex/conf. call
29-Sept-16	West TSTF Meeting	Eagan, Minn.

Table 4.1-1: MTEP16 Technical Study Task Force and 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 MTEP16 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 MTEP16 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.

MTEP16 contains Target Appendix A GIPs totaling approximately $140 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 ($)
10763	J392 Generation Upgrades	CETO	Not Shared	East	$874,000
10425	J340 Generation Interconnection	ITCT	Shared	East	$15,150,000
10743	Covert Gen Interconnection (PJM-T94)	METC	Shared	East	$3,605,000
10744	J392 Generation Interconnection	METC	Shared	East	$18,0872,200
11023	J392 Generator Interconnection	WPSC	Not Shared	East	$13,980,072
7944	J348 Generation Interconnection	EES-EAI	Not Shared	South	$2,526,158
10044	J348 Generation Interconnection	EES-EAI	Not Shared	South	$10,064,000
9957	J473 Generation Interconnection	SMEPA	Not Shared	South	$1,590,000
9969	J473 Generation Interconnection	SMEPA	Not Shared	South	$4,782,000
11383	J329 Network Upgrades	CFU-PMEU	Not Shared	West	$1,043,700
11463	C023 Stanton 31RB3	GRE	Not Shared	West	$33,033
9937	J233 Network Upgrades	ITCM	Not Shared	West	$17,740,415
9939	H009 Jasper -Aurora 69kV	ITCM	Not Shared	West	$3,720,000
9941	H021 Traer - Traer Tap 69 kV	ITCM	Not Shared	West	$293,449
10867	J285 Interconnection Facilities	MEC	Shared	West	$3,000,000
10868	J411 Interconnection Facilities (Ida Co. Substation)	MEC	Shared	West	$5,750,000

11103	Black Hawk: Install 2-69 kV Cap Banks	MEC	Not Shared	West	$1,180,000
11143	J274 Network Upgrades	MEC	Not Shared	West	$175,000
11144	R42 Network Upgrades Sub T(FD)	MEC	Not Shared	West	$88,000
11145	R42 Network Upgrades Sub T FD - Boone Jct 161 kV Line Uprate	MEC	Not Shared	West	$173,000
11146	J343 Network Upgrades Clarinda-Brooks 161 kV Uprate	MEC	Not Shared	West	$200,000
11283	J343 Network Upgrades Clarinda-Maryville 161 kV Uprate	MEC	Not Shared	West	$100,100
11284	J343 Network Upgrades Clarinda Substation	MEC	Not Shared	West	$80,500
11285	J344 Network Upgrades Beacon 161 kV Line Drops, Poweshiek	MEC	Not Shared	West	$25.000
11763	J344 Network Upgrades	ITCM	Not Shared	West	$5,537,540
11043	PJM Y1-069 Relay Modifications at Monroe to Accommodate PJM Y1-069 Lallendorf Generator Interconnection.	ITCT	Shared	East	250,000
11583	J301 Generation Interconnection.	ITCT	Shared	East	$9,497,000
11584	J308 Generation Interconnection	ITCT	Shared	East	$9,421,000.00
11603	J321 Generation Interconnection	ITCT	Shared	East	$9,366,000.00
11604	J419 Generation Interconnection	ITCT	Shared	East	$803,000
Total Estimated Cost					**$139,135,167**

Table 4.2-1 Generation Interconnection Projects in MTEP16 Target Appendix A[29]

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

GI Project No.	TO	County	ST	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
J392	METC	Otsego	MI	DPP-2015-FEB	NRIS	Livingston – Stover 138 kV Line	383.1	Gas	GIA
J340	ITCT	Huron	MI	DPP-2012-AUG	NRIS	Cosmo – Bad Axe 120 kV Line	100	Wind	GIA
PJM T94	METC	Van Buren	MI	N/A	N/A	Cook – Palisades 345 kV Line	1035	Gas	N/A
J348	EES-EAI	Arkansas	AR	DPP-2014-AUG	NRIS	Almyra -Stuttgart Ricuskey 115 kV Line	81	Solar	GIA
J473	SMEPA	Lamar	MS	DPP-2016-FEB	ERIS	Sumrall II 69 kV Substation	52	Solar	GIA
J329	CFU	Marion	IA	DPP-2014-AUG	NRIS	Pella West 69 kV Substation	55	Hydro	GIA
C023	GRE	Oliver	ND	02/04/16 Coordinated Study	N/A	Stanton 230 kV Substation	100	Wind	N/A
J233	ITCM	Marshall	IA	DPP-2013-AUG	NRIS	Marshalltown 161 kV Substation	635	Gas	GIA
H009	ITCM	Tama	IA	DPP-2012-AUG	ERIS	Trear – Marshalltown 161 kV Line	150	Wind	GIA
H021	ITCM	Grundy	IA	DPP-2012-AUG	NRIS	Wellsburg 115 kV Substation	138.6	Wind	GIA
J285	MEC	O'Brien	IA	DPP-2014-AUG	NRIS	O'Brien County 345 kV Substation	250	Wind	GIA
J411	MEC	Ida	IA	DPP-2015-FEB	NRIS	LeHigh – Raun 345 kV Line	300	Wind	GIA
G735	ITCM	Hancock	IA	DPP-2012-AUG	NRIS	Lime Creek 161 kV Substation	200	Wind	GIA
J274	MEC	Madison	IA	DPP-2013-AUG	NRIS	Winterset - Creston 161 kV Line	100	Wind	GIA
R42	MEC	Webster	IA	DPP-2012-AUG	NRIS	Lehigh 345 kV Substation	250	Wind	GIA
J343	MEC	Adams	IA	DPP-2014-AUG	NRIS	Creston - Clarinda 161 kV Line	150	Wind	GIA
J344	MEC	Mahaska	IA	DPP-2014-AUG	NRIS	Poweshiek – Oskaloosa 161 kV Line	169	Wind	GIA
PJM Y1-069	ITCT	Monroe	MI	N/A	N/A	Northern Ohio 345 kV	799	Gas	N/A
J301	ITCT	Tuscola	MI	DPP-2015-FEB	NRIS	Bauer – Rapson 354 kV Line	101	Wind	GIA
J308	ITCT	Sanilac	MI	DPP-2015-FEB	NRIS	Rapson – Banner 345 kV Line	301	Wind	GIA
J321	ITCT	Sanilac	MI	DPP-2015-FEB	NRIS	Rapson – Banner 345 kV Line	151.2	Wind	GIA
J419	ITCT	Washtenaw	MI	DPP-2015-FEB	NRIS	Milan 120 kV Substation	100	Solar	GIA

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

Figure 4.2-1: Generation Interconnection Requests Associated with MTEP16 Target Appendix A

MTEP16 Target Appendix A

Generation Interconnection Projects – Detail

MTEP Project 10763 – Consumers Energy Transmission Owner

- Perform Network Upgrades for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Upgrade the Emmet 138 kV Sub Relaying
- Add a wavetrap to the Emmet – Livingston 138 kV Line to accommodate the addition of a dual-pilot relay scheme
- Completion date: June 17, 2016
- Actual cost: $874,000

MTEP Project 10425 – International Transmission Co. Transmission

- Perform Network Upgrades for J340 GIP
- J340 – 100 MW Wind Generator
- Point of interconnection: Cosmo – Bas Axe 120 kV Line
- Rebuild 5.3 miles of the existing 120 kV Cosmo Tap to Double Circuit steel poles
- Relocate the Harvest Wind Tap point
- String 954 ACSR to create the new J340 Harvest Wind-Grassmere 120 kV Line
- Expand the Grassmere Sub and install 1-345 kV Breaker, a 345/120 kV Transformer, and a 120 kV Breaker on the low side of the Transformer to tie in the new line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $15,150,000

MTEP Project 10743 – Michigan Electric Transmission Co.

- Perform Network Upgrades for PJM-T94 – Covert GIP
- PJM-T94 – 1,035 MW Gas Generation
- Point of interconnection: Cook – Palisades (Covert) 345 kV Line
- Construct a new control house at Palisades Sub and replace the relaying associated with positions RH25 and FH27
- Install OPGW on the new Palisades - Segreto #1 345 kV Line and remove the METC SCADA equipment at the new Covert 345 kV Sub
- Completion date: September 30, 2015
- Actual Cost: $3,605,000

MTEP Project 10744 – Michigan Electric Transmission Co.

- Perform Network Upgrades determined in the FEB2015 DPP for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Wolverine to construct the following:
    - New 4 row, 11 Breaker, 138 kV Van Tyle Breaker and a half Sub (Ownership will be transferred to METC upon completion)

  - Loop the 138 kV Livingston - Stover Line into Van Tyle 138 kV Sub, and rebuild the new Livingston - Van Tyle line to double circuit structures with OPGW being added to the new poles
  - 1431 ACSR conductor will be installed on both sides of the new structures to create Livingston - Van Tyle #1 and #2 Lines
  - A dual pilot relaying scheme will be installed on the Livingston - Emmet 138 kV line and the Livingston Sub will be expanded to include 2 new rows, and 5 additional Breakers on the 138 kV Breaker and a half Sub
  - Relaying upgrades at Gaylord Sub
- Completion date: June 11, 2016
- Actual Cost: $18,087,200

MTEP Project 11023 – Wolverine Power Supply Cooperative

- Perform Network Upgrades determined in the FEB2015 DPP for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Wolverine to construct the following:
  - Advance 138 kV Sub and 138/69 kV Transformers
  - Gaylord 138 kV 4 Breaker ring bus to accommodate a 3rd line into the station (2016)
  - Gaylord 138 kV 6 Breaker ring bus and 2nd 138/69 kV Transformer (2018)
  - Upgrades to Elmira, Deer Lake and Alpine distribution Subs from 69 kV to 138 kV
  - Conversion of existing Gaylord - Advance 69 kV Line to 138kV, new lines will be Gaylord - Van Tyle and Van Tyle to Advance
  - Rebuild the Gaylord - Livingston 138 kV Line with 795 ACSS
- Completion date: April 30, 2016
- Actual Cost: $13,989,072

MTEP Project 7944 – Entergy - Arkansas

- Perform Network Upgrades for J348 GIP
- J348 - 81 MW Solar Generator
- Point of interconnection: P Stuttgart Ricuskey - Stuttgart Ind.115 kV Line
- Upgrade the Stuttgart Ricuskey - Stuttgart Ind.115 kV Line to 176 MVA
- Anticipated completion date: January 30, 2018
- Anticipated cost: $2,526,158

MTEP Project 10044 – Entergy - Arkansas

- Perform Network Upgrades for J348 GIP
- J348 - 81 MW Solar Generator
- Point of interconnection: Stuttgart Ricuskey - Almyra 115 kV Line
- New 115 kV 3 Breaker ring bus Switching Station named Goodwin Road on the Stuttgart Ricuskey - Almyra 115 kV Line
- Anticipated completion date: January 30, 2018
- Anticipated cost: $10,064,000

MTEP Project 9957 – Southern Mississippi Electric Power Association

- Perform Network Upgrades for J473 GIP Origis Solar Project - Sub
- J473 – 52 MW Solar Generator.

- Point of interconnection: Sumrall – Rawls 69 kV Line
- New 69 kV Switching Station with a 69/26.4 kV GSU
- The Origis Energy solar plant will tap the existing SMEPA 69 kV Line 42 (Sumrall - Rawls Springs) approximately 5.6 miles from Sumrall 69 kV Sub
- The generation interconnection project is contingent upon the following injection upgrades:
    - Line 42 and 43 (Columbia - Sumrall) will be uprated to a higher conductor temperature via structural changeouts to support the generation addition
    - OPGW will also be installed for communications
- Anticipated completion date: March 23, 2017
- Anticipated cost: $1,590,000

MTEP Project 9969 – Southern Mississippi Electric Power Association

- Perform Network Upgrades for J473 GIP Origis Solar Project - Transmission
- J473 – 52 MW Solar Generator.
- Point of interconnection: Sumrall – Rawls 69 kV Line
- New 69 kV Switching Station with a 69/26.4 kV GSU
- The Origis Energy solar plant will tap the existing SMEPA 69 kV Line 42 (Sumrall - Rawls Springs) approximately 5.6 miles from Sumrall Sub
- The generation interconnection project is contingent upon the following injection upgrades:
    - Line 42 and 43 (Columbia - Sumrall) will be uprated to a higher conductor temperature via structural changeouts to support the generation addition
    - OPGW will also be installed for communications
- Anticipated completion date: March 22, 2017
- Anticipated cost: $4,782,000

MTEP Project 11383 – Cedar Falls Utilities

- Perform Network Upgrades for J329 GIP on Subs in Pella, Iowa.
- J329 - 55 MW Hydro Generator
- Point of interconnection: Pella West 69 kV Sub
- Anticipated completion date: August 1, 2017
- Anticipated cost: $1,043,700

MTEP Project 11463 – Great River Energy

- Perform Network Upgrades for C023 GIP
- C023 – 100 MW Wind Generator
- Point of interconnection: Stanton 230 kV Sub
- Jumper replacement inside Stanton Sub at 230 kV Breaker 31RB3
- Anticipated completion date: November 1, 2016
- Anticipated cost: $33,033

MTEP Project 9937 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for J233 GIP
- J233 - 635 MW CT Combined-Cycle Combustion Turbine Generator
- Point of interconnection: Marshalltown (Sutherland) 161 kV Sub
- Replace existing 161/69 kV Transformers with 150 MVA units at Fernald, Jasper and Newton Subs
- Uprate the Marshalltown - Blairstown Junction 115 kV line to 90 MVA

- Uprate the Jasper - Laurel 161 kV to 361 MVA
- Remove sag limit from Jasper - Newton 161 kV Line to allow operation at 276 MVA
- Rebuild the ITCM portion of the Newton - Prairie City 69 kV Line with T2-4/0 ACSR to allow operation at the MEC rating of 40 MVA
- Anticipated Completion date: March 30, 2017
- Anticipated Cost: $17,740,415

MTEP Project 9939 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for H009 GIP
- H009 – 150 MW Wind Generator
- Point of interconnection: Jasper - Aurora Heights 69 kV Line
- Rebuild Jasper - Aurora Heights 69 kV Line with T2-477 ACSR
- Anticipated completion date: December 31, 2016
- Anticipated cost: $3,720,000

MTEP Project 9941 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for H021 GIP
- H021 – 138.6 MW Wind Generator
- Point of interconnection: Trear – Trear Tap 69 kV Line
- Upgrade the Traer - Trear Tap 69 kV Line
- Completion date: June 1, 2016
- Actual Cost: $293,449

MTEP Project 10867 – MidAmerican Energy Co.

- Perform Network Upgrades for J285 GIP
- J285 – 250 MW Wind Generator
- Point of interconnection: O'Brien County 345 kV Sub
- Add one 345 kV circuit breaker position at the Obrien County Sub 345 kV ring bus
- Completion date: August 15, 2016
- Actual cost: $3,000,000

MTEP Project 10868 – MidAmerican Energy Co.

- Perform Network Upgrades for J411 GIP
- J411 – 250 MW Wind Generator
- Point of interconnection: Raun – Lehigh 345 kV Line
- New 3-terminal 345 kV ring bus Sub (Ida County Sub), bisecting the Raun - Lehigh 345 kV Line
- Install new transposition structures for the Raun - Ida County and Ida County - Lehigh 345 kV Lines (ITCM will have an ownership share of the network transmission facilities)
- Completion date: July 15, 2016
- Actual Cost: $5,750,000

MTEP Project 11103 – MidAmerican Energy Co.

- Install two 69 kV Capacitor Banks at the Black Hawk Sub
- G735 – 200 MW Wind Generator
- Point of interconnection: Lime Creek 161 kV Line
- Add two 69kV, 15 MVAR Capacitor Banks at the Black Hawk 69 kV Sub

- Anticipated completion date: November 15, 2016
- Anticipated cost: $1,180,000

MTEP Project 11143 – MidAmerican Energy Co.

- Perform Network Upgrades on the Creston - Macksburg 161 kV Line
- J274 – 100 MW Wind Generator
- Point of interconnection: Winterset – Creston 161 kV Line
- Structure replacements on the Creston-Macksburg 161 kV Line
- Anticipated completion date: December 1, 2016
- Anticipated cost: $175,000

MTEP Project 11144 – MidAmerican Energy Co.

- Perform Network Upgrades on the Sub T(FD) 161 kV Sw 11-817
- R42 – 250 MW Wind Generator
- Point of interconnection: Lehigh 345 kV Sub
- Replace 161 kV Switch 11-817 at the 161 kV Sub T(FD)
- Completion date: June 24, 2016
- Actual Cost: $88,000

MTEP Project 11145 – MidAmerican Energy Co.

- Perform Network Upgrades on the Sub T FD - Boone Jct 161 kV Line
- R42 – 250 MW Wind Generator
- Point of interconnection: Lehigh 345 kV Sub
- Structure replacements on the Sub T(FD) – Boone Jct 161 kV Line
- Completion date: June 30, 2016
- Actual Cost: $173,000

MTEP Project 11146 – MidAmerican Energy Co.

- Perform Network Upgraders on the Clarinda - Brooks 161 kV Line
- J343 – 150 MW Wind Generator
- Point of interconnection: Creston – Clarinda 161 kV Line
- Structure replacements on the Clarinda - Brooks 161 kV Line
- Anticipated completion date: June 1, 2017
- Anticipated cost: $200,000

MTEP Project 11283 – MidAmerican Energy Co.

- Perform Network Upgrades on the Clarinda - Maryville 161 kV Line
- J343 – 150 MW Wind Generator
- Point of interconnection: Creston – Clarinda 161 kV Line
- Three structure replacements on the Clarinda - Maryville 161 kV Line
- Anticipated completion date: June 1, 2017
- Anticipated cost: $100,100

MTEP Project 11284 – MidAmerican Energy Co.

- Replace 161 kV Switch 803L at the Clarinda 161 kV Sub
- J343 – 150 MW Wind Generator

- Point of interconnection: Creston – Clarinda 161 kV Line
- Install a new 161 kV line disconnect switch at Clarinda 161 kV Sub on the line terminal to Maryville
- Replace associated line drops and jumpers, remove existing switch
- Anticipated completion date: June 1, 2017
- Anticipated cost: $80,500

MTEP Project 11285 – MidAmerican Energy Co.

- Perform Network Upgrades - Beacon 161 kV Sub
- J344 – 169 MW Wind Generator
- Point of interconnection: Poweshiek - Oskaloosa 161 kV Line
- Replace the line drops at the Beacon 161 kV Sub on the Beacon – Poweshiek 161 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $25,000

MTEP Project 11763 – International Transmission Co. - Midwest

- Perform Network Upgrades – Irvine Switch
- J344 – 169 MW Wind Generator
- Point of interconnection: Poweshiek - Oskaloosa 161 kV Line
- New 3-Terminal, 3-Breaker Irvine ring bus Sub on the Poweshiek – Beacon 161 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $5,537,540

MTEP Project 11043 – International Transmission Co. - Transmission

- Perform modifications at Monroe for the Lallendorf GIP
- PJM-Y1-069 799 MW Gas Generator in First Energy
- Point of interconnection: Northern Ohio 345 kV Line
- Perform relay modifications and install a new wave trap at Monroe
- Completion date: April 1, 2016
- Actual cost: $250,000

MTEP Project 11583 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J308 GIP
- J301 – 101 MW Wind Generator
- Point of interconnection: Bauer – Rapson 345 kV Line
- New 345kV, 3 Breaker Sub fed by Looping the Bauer – Ringle 345 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,497,000

MTEP Project 11584 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J308 GIP
- J308 – 301 MW Wind Generator
- Point of interconnection: Rapson – Banner 345 kV Line
- New 345kV, 3 Breaker Sub with Relay Upgrades
- 0.1 Miles of Double Circuit 345 kV Line to the new Sub, tapping Greenwood – Rapson 345 kV Line

- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,421,000

MTEP Project 11603 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J321 GIP
- J321 – 151.2 MW Wind Generator
- Point of interconnection: Rapson – Banner 345 kV Line
- New 345kV, 3 Breaker Sub in a Ring Bus configuration
- Loop Greenwood – Rapson #2 345 kV Line into the new Sub
- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,366,000

MTEP Project 11604 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J419 GIP
- J419 – 100 MW Solar Generator
- Point of interconnection: Milan 120 kV Substation
- Install a 120 kV Breaker with associated disconnects at Milan Substation
- Extend bus 103
- Anticipated completion date: June 30, 2018
- Anticipated cost: $803,000

The Queue Process

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

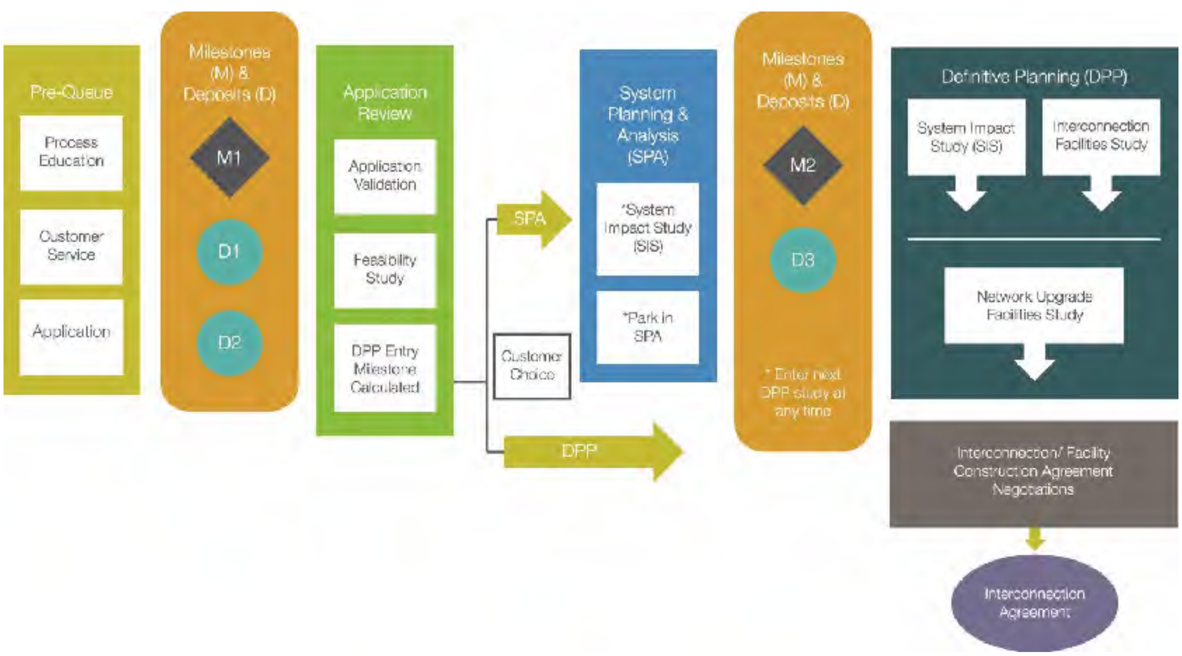


Figure 4.2-2: Generator Interconnection Queue Process

Since the beginning of the queue process, MISO and its Transmission Owners have received approximately 1,734 generator interconnection requests totaling 343GW (Figures 4.2-3 and 4.2-4). Among them, 56 GW out of the 343 GW or 16 percent are now connected to the transmission system. These generation additions enhance reliability, ensure resource adequacy, provide a competitive market to deliver benefit to ratepayers, and help the industry meet renewable portfolio standards.

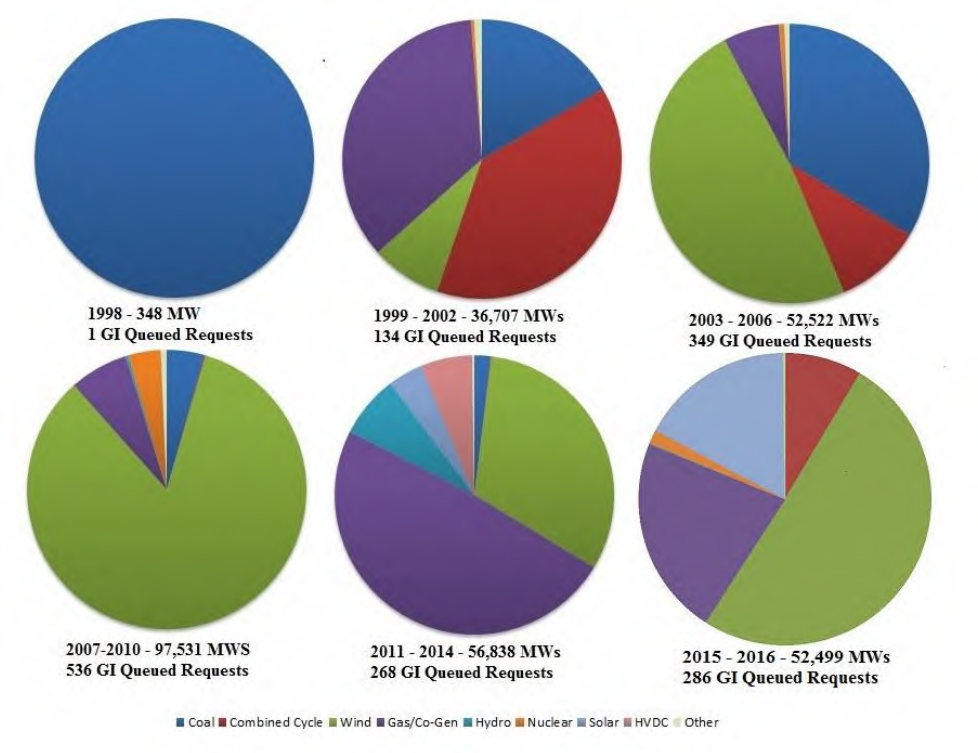


Figure 4.2-3: Queue trends

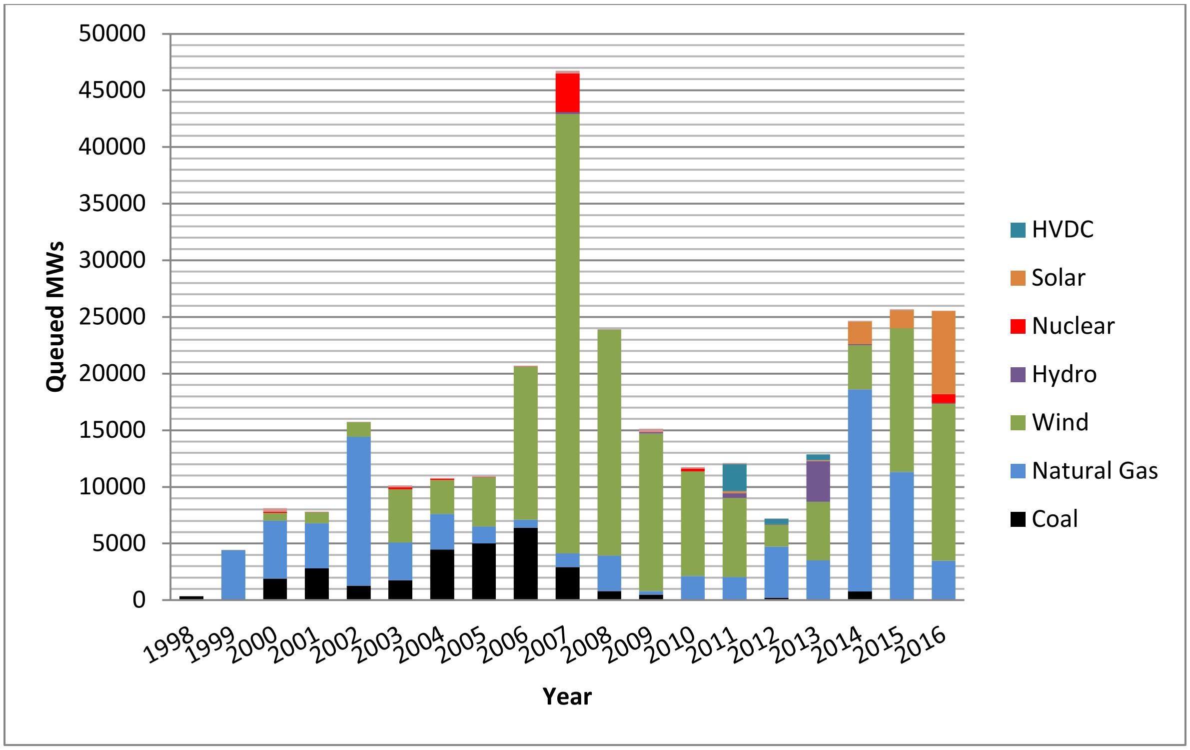


Figure 4.2- 4: Queue Trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. Although there is no RPS program in place at the national level, 29 states and the District of Columbia had enforceable RPS or other mandated renewable capacity policies. In addition, eight states adopted voluntary renewable energy standards. Between 2005 and 2008, MISO experienced exponential growth in wind project requests. In 2007, wind generation requests in the MISO queue peaked at approximately 39 GW. These requests reflect the dramatic increase in registered wind capacity in the MISO footprint (Figure 4.2-5).

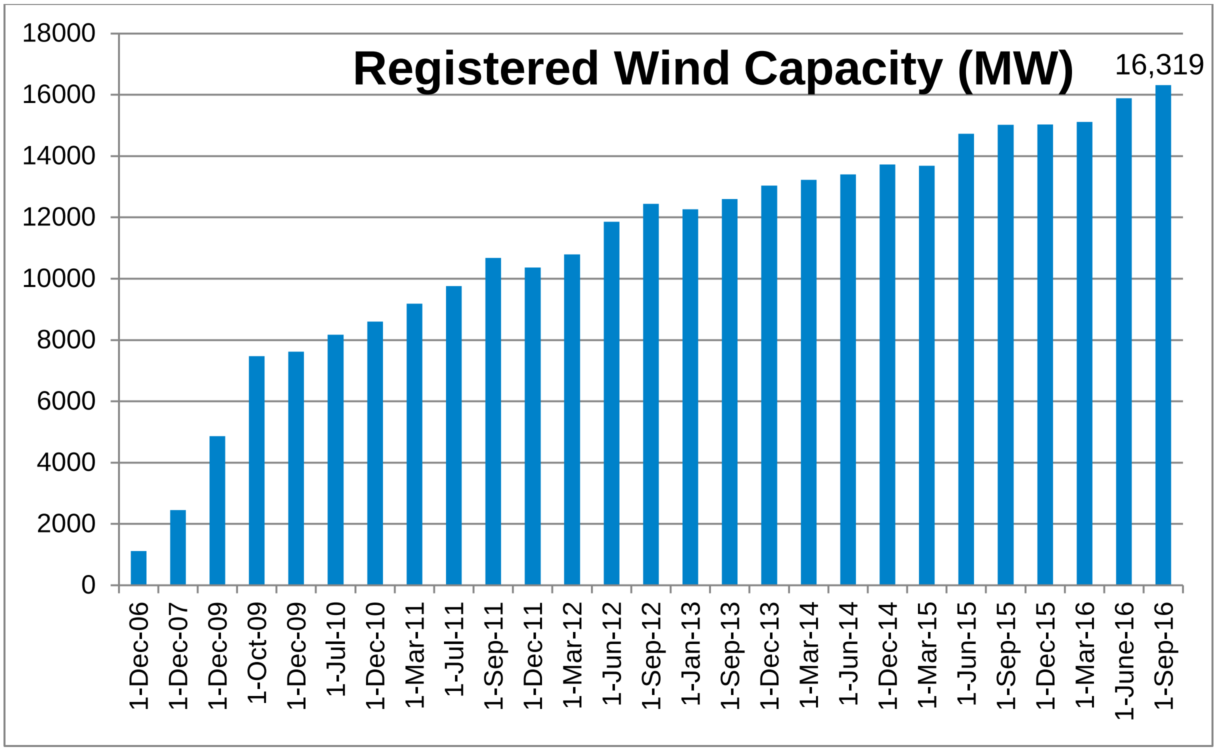


Figure 4.2-5: Nameplate Wind Capacity Registered for MISO

As a result of the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and its compliance requirements, MISO's generator interconnection queue has seen fluctuation in natural gas interconnection requests (Table 4.2-3). Data corresponding to year 2016 only includes natural gas requests for the first three quarters.

Year	Gas Requests (MW)	% Of All New Requests
2016	4,472*	4.2%
2015	9,076	35%
2014	9,424	58%
2013	3,835	30%
2012	4,509	63%

*Natural Gas MW requested as of October 2016

Table 4.2-3: Recent-year Natural Gas Requests

Furthermore, there are about 2.5 GW of solar generation interconnection in definitive planning phase (DPP) as of August 2016. This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic (PV) modules.

Process Improvement

Over the past 10 years, the MISO Interconnection Process has evolved from first-in, first-out methodology to first-ready, first-served methodology to expedite the generation project queue lifecycle and maintain system reliability.

With significant changes implemented on the latest 2012 Interconnection Queue Reform, which largely addressed backlogs in the generator interconnection queue and late-stage terminations of generator interconnection agreements, the MISO queue still undergoes 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.

The goal of this effort is to review the current process and study criteria, and identify areas for further improvement. Some other process improvement focus areas that MISO has been working 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 AFC values by MISO Tariff Administration.

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

From July 2015 to June 2016, MISO Transmission Service Planning processed 219 long-term TSRs (Figure 4.3-1) and completed 16 System Impact Studies for a total of 17 TSRs. Of these System Impact Studies, five TSRs were confirmed, one was refused, none executed a Facilities Study Agreement and 11 await the completion of corresponding external Affected System Impact Studies. Remainders of TSRs were either rollover TSRs or had the same point-of-receipt/point-of-delivery Local Balancing Authority, which don't require a system impact study.

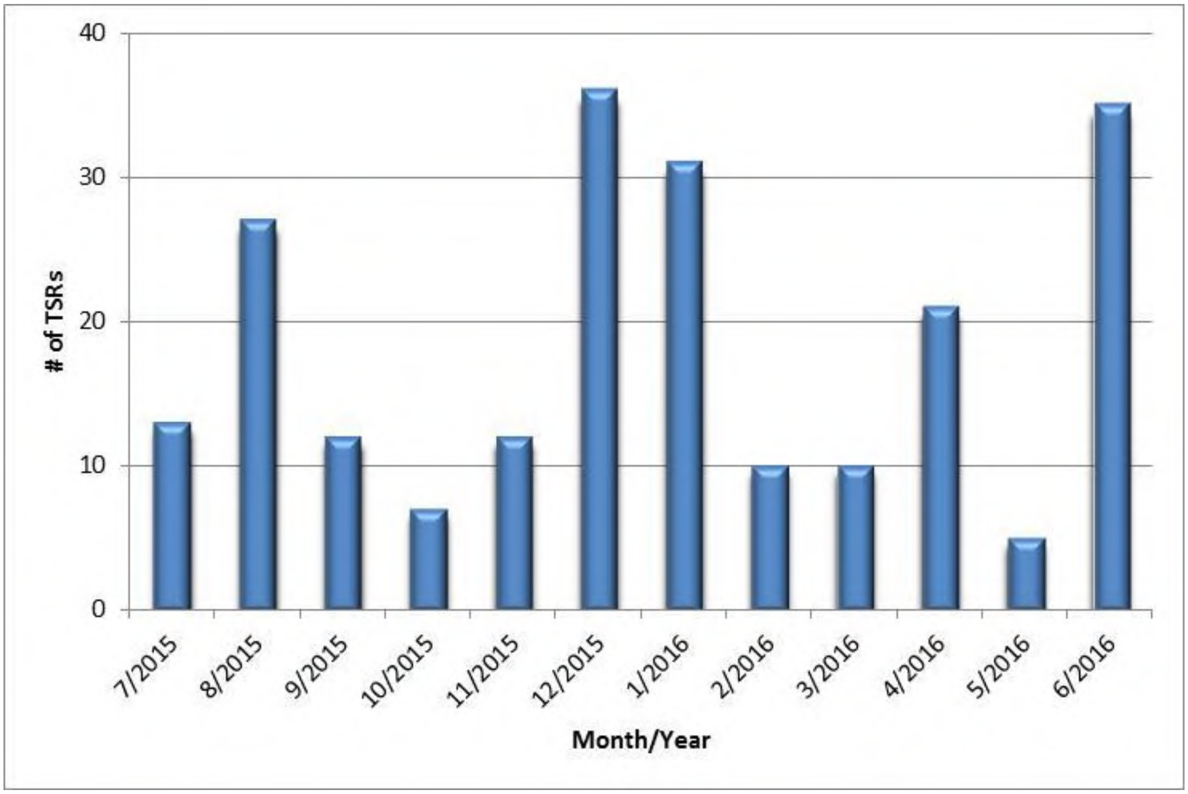


Figure 4.3-1: MISO Long-Term TSRs processed from July 2015 through June 2016

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

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

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

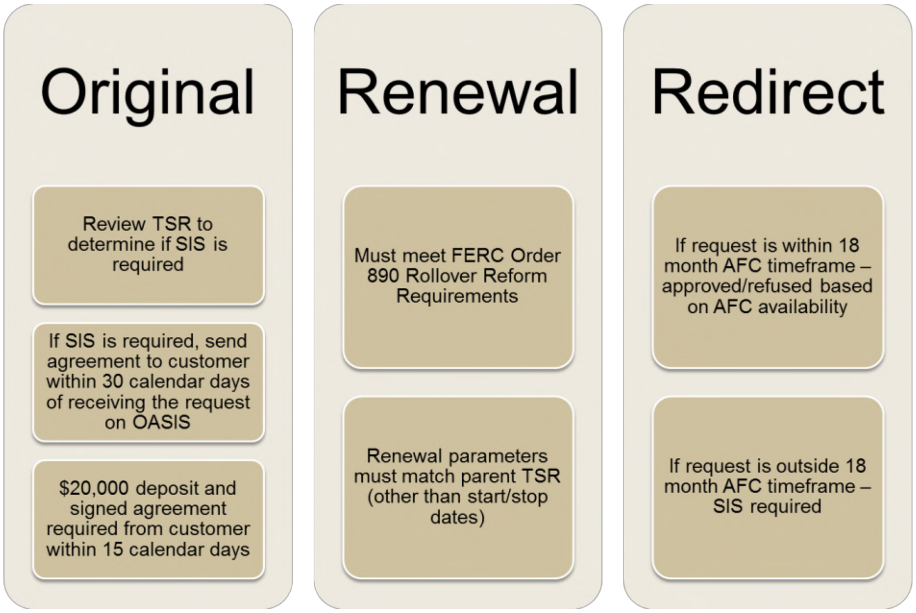


Figure 4.3-2: TSR Triage Phase Processing

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

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

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

Transmission Service Restriction

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

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

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

4.4 Generation Retirements and Suspensions

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

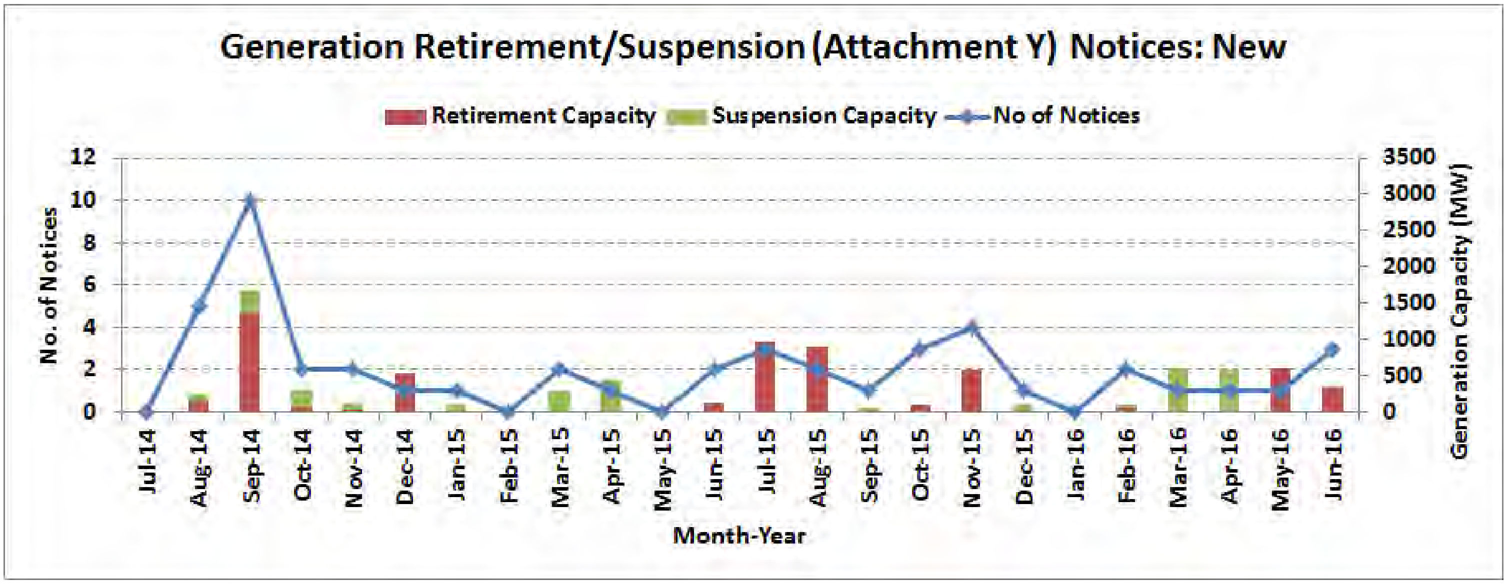
The permanent or temporary cessation of operation of generation resources can significantly impact the reliability of the transmission system. The MISO Attachment Y process provides a mechanism to ensure Transmission System reliability in response to the retirement or suspension of a generation resource.

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 eight Attachment Y Notices (2,288 MW) for unit retirement/suspension during the first six months of 2016 (Figure 4.4-1). In the same period (January-June) in 2015 MISO received six Attachment Y retirement/suspension notices (964 MW) (Figure 4.4-1). MISO completed assessments and resolved nine Attachment Y Notices (2,081 MW) for unit retirement/suspension in the first six months of 2016 (Fig 4.4-2).

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



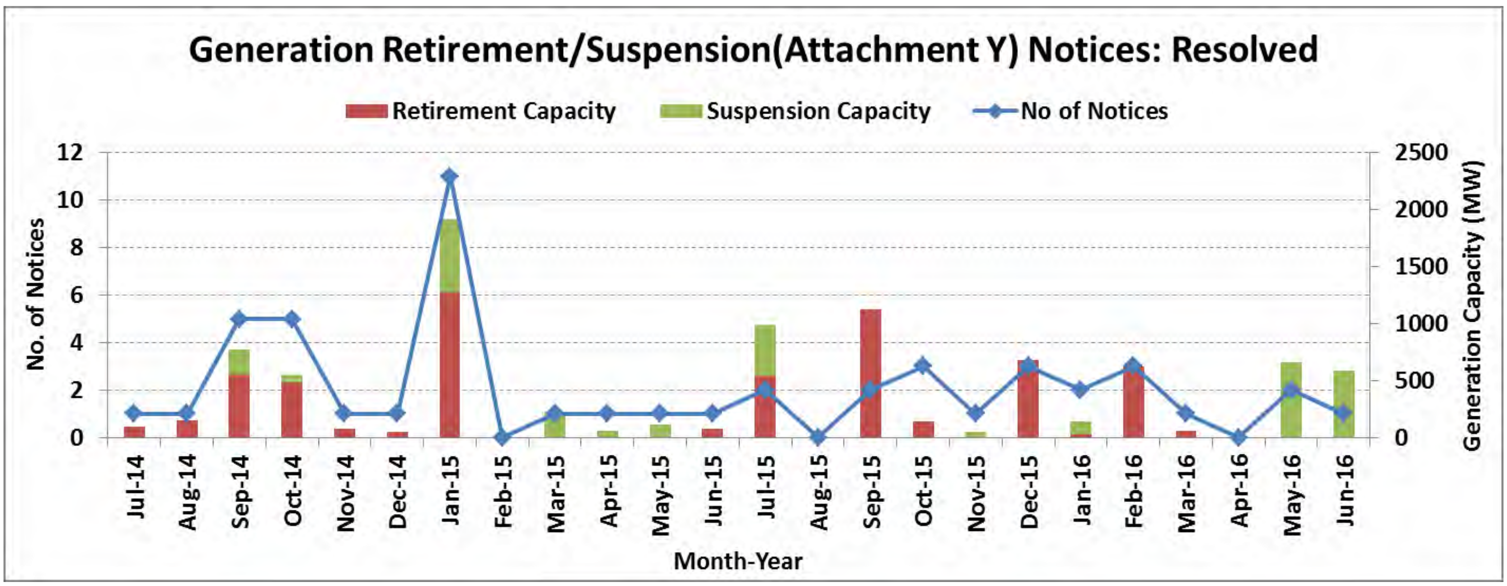


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 4,847 MW of generation capacity is retiring in 2016 and an additional 69 MW of generation capacity will retire in 2017 (Figure 4.4-2). This includes 3,068 MW of coal generation, 1,722 MW of gas generation and 57 MW of diesel/biomass generation that is approved for retirement in 2016 and 69 MW of coal generation in 2017. The data suggests that majority of retirements in 2016 are related to compliance with the Mercury and Air Toxics Standards.

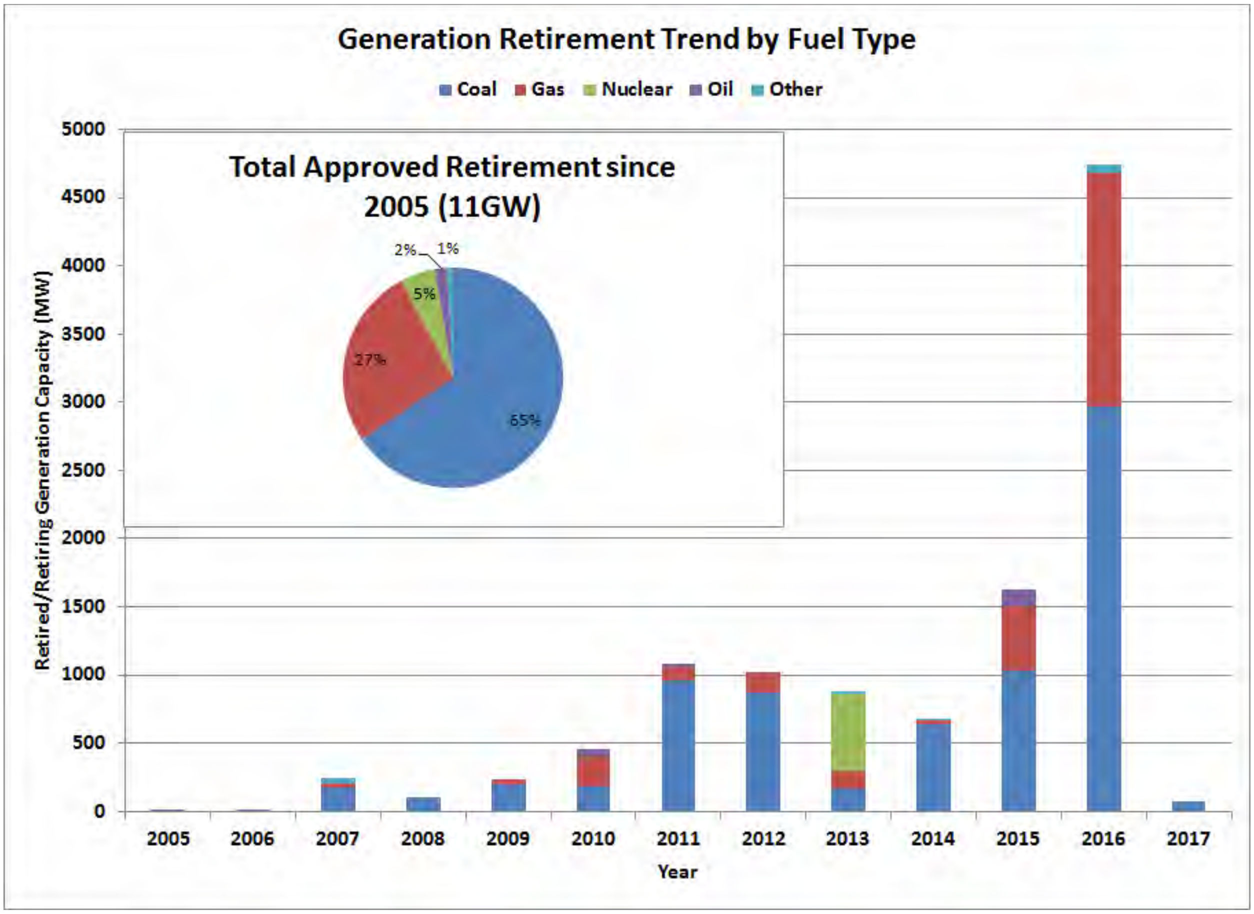


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2016 FERC Order on Cost Allocation

In May 2016, FERC issued an order accepting the new cost allocation method developed by MISO that assigns cost responsibility to the load-serving entities (LSE) whose loads benefit from the operation of the SSR unit. FERC directed MISO to file a plan to re-allocate costs previously assigned under the SSR Agreements for Escanaba 1 & 2, Presque Isle 5-9, White Pine 1 and White Pine 2.

SSR Agreement Activity

Since the inception of the SSR program in 2005, MISO has implemented nine SSR Agreements with only one agreement remaining active for White Pine Unit 1.

White Pine 1 (20 MW) – The owner of the White Pine plant in the Upper Peninsula of Michigan requested to retire Unit 1 on April 16, 2014, and MISO determined that White Pine Unit 1 is needed as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement was established for April 16, 2014, to April 15, 2015 and recently was renewed for a third term from April 16, 2016 to April 15, 2017. In July 2016, a transmission reconfiguration plan was proposed as an alternative to the SSR Agreement and determined to be an acceptable solution to allow the retirement of White Pine Unit 1. MISO filed with FERC to terminate the White Pine Unit 1 SSR Agreement effective November 26, 2016.

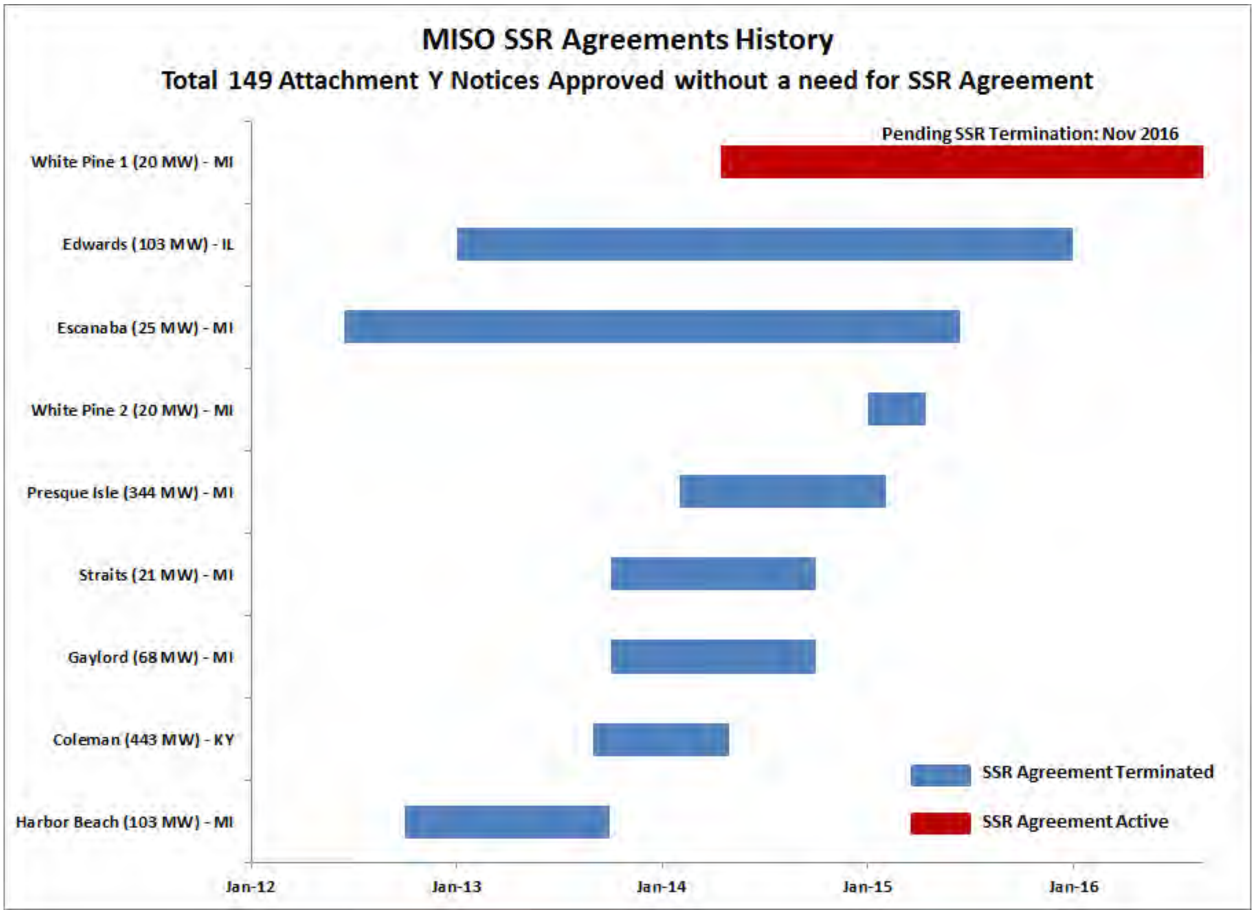


Figure 4.4-3: SSR History

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 reliability analysis with the participation of the TOs to determine if any violations of applicable NERC and TO planning criteria are caused by the unit retirement/suspension.

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

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

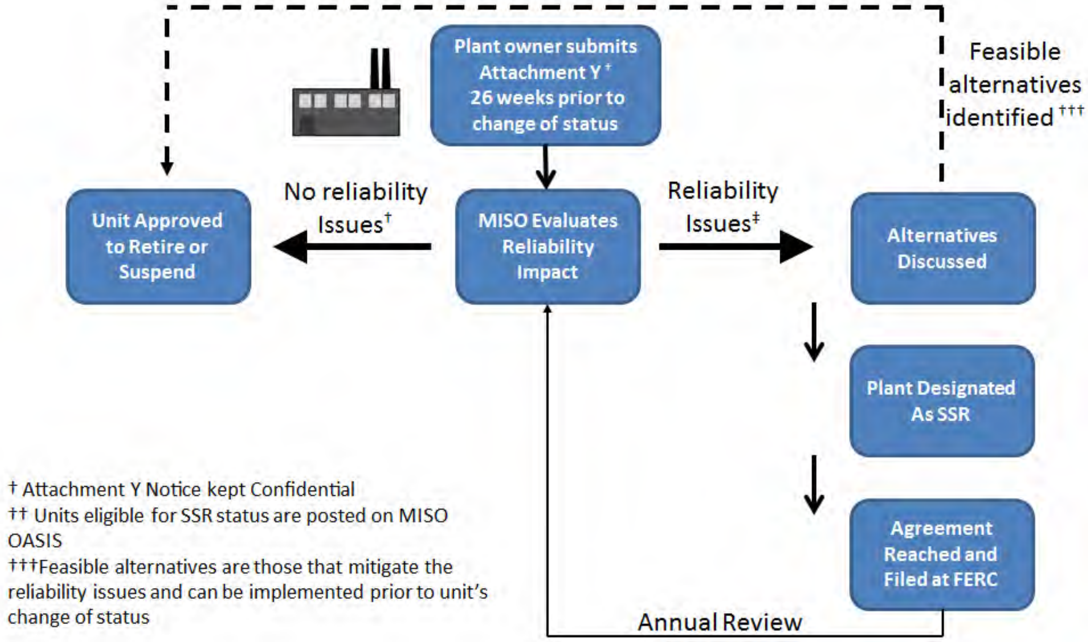


Figure 4.4-4: MISO Attachment Y process

4.5 Generator Deliverability Analysis

MISO performs generator deliverability analysis as a part of the MTEP16 process to ensure continued deliverability of generating units with Network Resource Interconnection Service (NRIS). Results of the assessment are based on an analysis of near-term (five-year) and long-term (10-year) summer peak scenarios.

Analysis results show a total of about 4,400 MW of deliverability is restricted due to constraints in the MTEP16 near-term scenario. This level is reduced to about 1,800 MW when longer term planned solutions through 2026 are considered. Constraints observed that are restricting generation beyond the established network resource amounts will be mitigated, with constraints with identified mitigation (Figure 4.5-1).

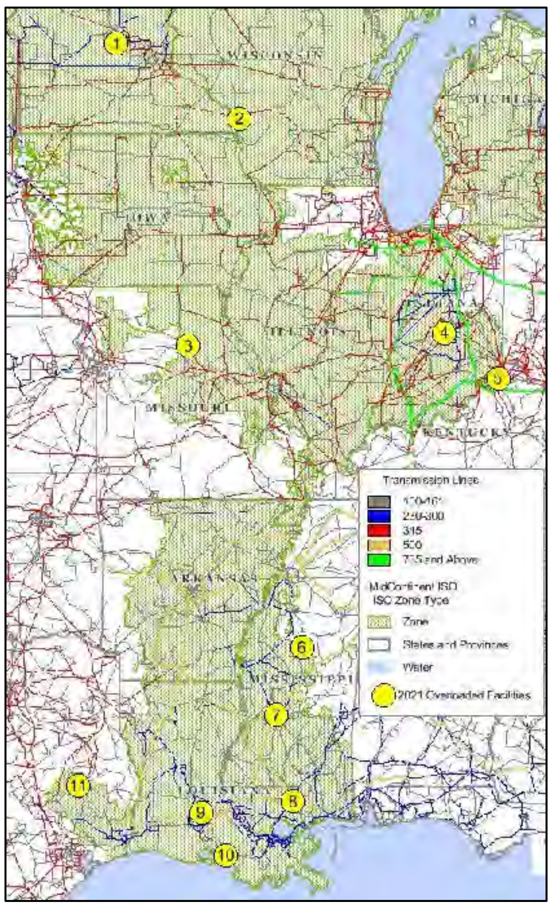


Figure 4.5-1: MTEP16 2021 generator deliverability constraints with defined mitigation

This analysis revealed 18 constraints that restrict existing deliverable amounts (Table 4.5-1) in the 2021 scenario with four constraints with identified mitigation. Mitigation for other constraints are being identified and will be included in MTEP17, as appropriate. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.5-1:

- “Overload Branch” is caused by bottling-up of aggregate deliverable generation
- “Area” is the Transmission Owner of the facility
- “Map ID” is the approximate location of the overloaded element (Figure 4.5-1)
- “Mitigation Required” represents constraints that were observed in both the near-term (five-year) and long-term (10-year) analysis.
- “MW Restricted” is the total amount of Network Resource Interconnection Service that is limited by the overloaded branch.

Overloaded Branch	Area	Map ID	Mitigation Required	MW Restricted
Markland 138 kV - He Belle Terra 138 kV	DEI	5	Yes	10.6
Stout CT 138 kV - Stout North 138 kV	IPL	4	Yes	12.08
Ray Braswell SES 500 kV - Franklin 500 kV	EES-EMI	7		3065.67
Miami Street 115 kV - Monument Street 115 kV	EES-EMI	7		36.19
Rex Brown 115 kV - Monument Street 115 kV	EES-EMI	7		197.66
Grenada South 115 kV - Elliot 115 kV	EES-EMI	6		106.44
Magnolia Groveton 138 kV - Staley 138 kV	EES	11		99
Bogalusa 500 kV - Adams Creek 230 kV	EES	8		2224.65
Horner 69 kV - Sinnock 69 kV	AMMO	3		1.07
Bayou Sale 138 kV - WaxLake 138 kV	CLEC	10		169.91
Coughlin 138 kV - Plaisance 138 kV	CLEC	9	Yes	511.83
Teche 138 kV - Bayou Sale 138 kV	CLEC	10		277.25
WaxLake 138 kV - El Paso Tap 138 kV	CLEC	10		65.02
La Crosse 69.0 kV - West Salem 69.0 kV	XEL	2	Yes	31.13
Franklin 500 kV - Bogalusa 500 kV	EES-EMI	8		4684.58
Plaisance 138 kV - Champagne 138 kV	EES-CLEC	9		42.97
Maple Lake 69 kV - Annandale 69 kV	GRE	1		3.96
Lakeover 500 kV - Lakeover 115 kV	EES-EMI	7		120.22

Table 4.5-1: MTEP16 Near-term constraints that limit deliverability of about 4,400 MW of network resources

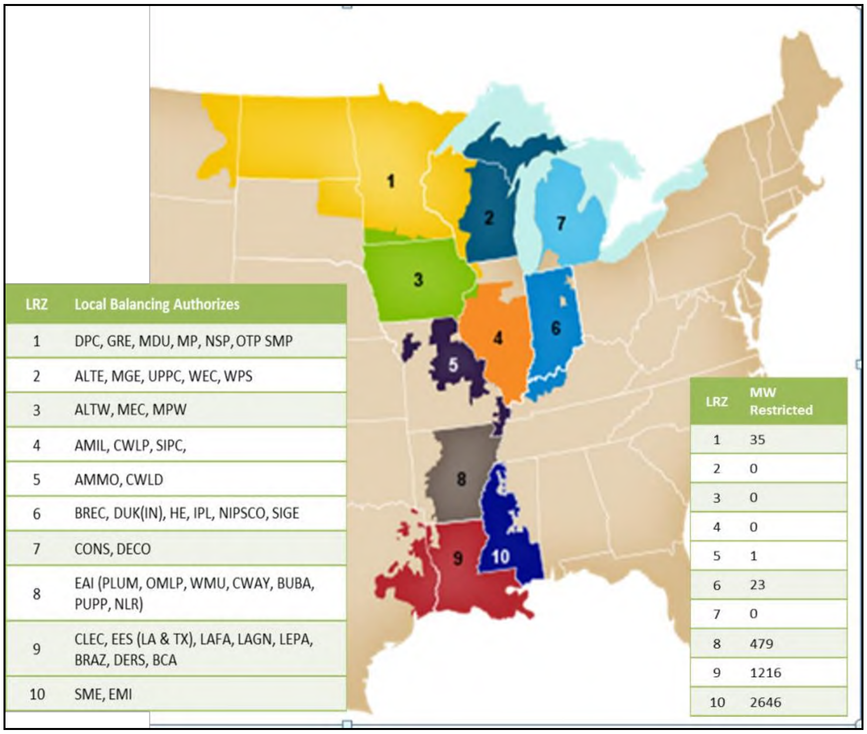
Additional 2026 constraints will be monitored in future MTEP studies to determine if mitigation is required through the MTEP generator deliverability process. Appendix D6 lists detailed results for the 2026 constraints and impacted NRIS projects.

FERC Order 2003 mandated that "Network Resource Interconnection Service" provides for all of the network upgrades that would be needed to allow the Interconnection Customer to designate its Generating Facility as a Network Resource and obtain Network Integration Transmission Service. Thus, once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades[30] to be funded by the Interconnection Customer.

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

Constraints recognized as needing mitigation were identified in the near-term 2021 planning scenarios, or as a recurring constraint in the long-term planning scenario. Deliverability was tested only up to the granted network resource levels of the existing and future network resource units modeled in the MTEP16 2021 case. No new interconnection service is granted through the annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

The total MW restricted varies in the near term and is summarized by Local Resource Zone (Figure 4.5-3).



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC,
5	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	35
2	0
3	0
4	0
5	1
6	23
7	0
8	479
9	1216
10	2646

Figure 4.5-3: Local Resource Zones (LRZ)

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

Since MTEP09, MISO has performed annual generator deliverability studies to better monitor the restricted megawatts and Network Resources. The 4,400 MW of restricted deliverability from MTEP16 compares to 4,100 MW in MTEP15, 3,800 MW in MTEP14, 500 MW in MTEP13, 1,000 MW in MTEP12, 350 MW in MTEP11, 900 MW in MTEP10 and approximately 3,000 MW of restricted deliverability in MTEP09 (Figure 4.5-4).

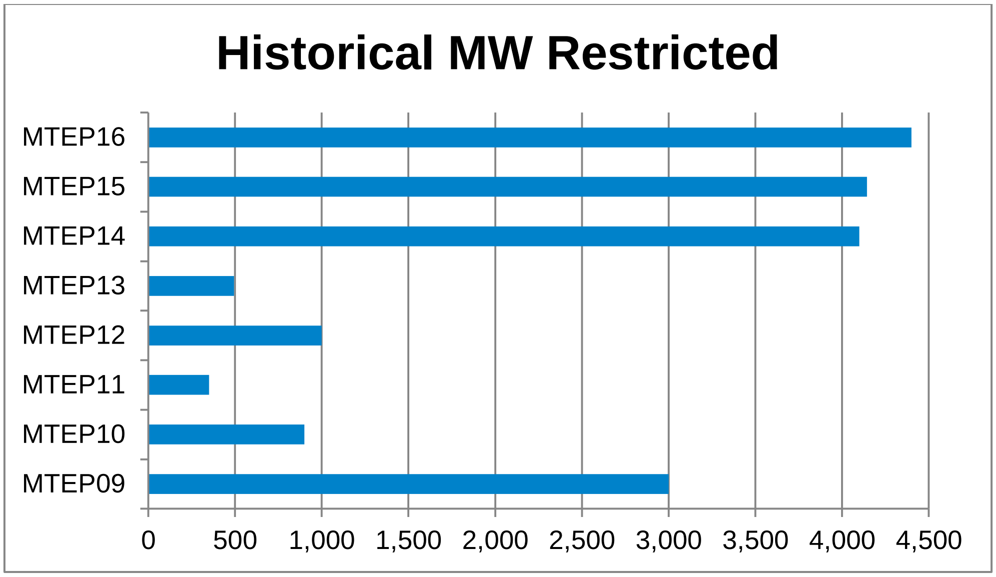


Figure 4.5-4: Restricted MW identified through MTEP cycles

The analysis of the 2026 scenario revealed 48 constraints that restrict existing deliverable amounts (Table 4.5-2) with 10 constraints requiring mitigation. Six of the 10 constraints were observed in the near-term 2021 scenario, in which mitigation was requested. The other four constraints are observed in last year's long-term (10-year-out) scenario, and therefore would require mitigation to resolve this repetitive overload. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.5-2:

- "Area Name" is the Transmission Owner of the facility
- "Overload Branch" is caused by bottling-up of aggregate deliverable generation
- "2021 Constraint" shows if the overloaded branch also existed in MTEP16 near-term (five-year) results
- "Mitigation Identified" represents constraints with identified mitigation. Mitigation will also be evaluated for the remaining 2021 constraints shown in the table

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
DEI	Markland 138 kV - He Belle Terra 138 kV	Yes	Yes
IPL	Stout CT 138 kV - Stout North 138 kV	Yes	Yes
EES-EMI	Ray Braswell SES 500 kV - Franklin 500 kV	Yes	
EES-EMI	Miami Street 115 kV - Monument Street 115 kV	Yes	
EES-EMI	Rex Brown 115 kV - Monument Street 115 kV	Yes	

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
EES-EMI	Grenada South 115 kV - Elliot 115 kV	Yes	
EES	Magnolia Groveton 138 kV - Staley 138 kV	Yes	
EES	Bogalusa 500 kV - Adams Creek 230 kV	Yes	
AMMO	Horner 69 kV - Sinnock 69 kV	Yes	
CLEC	Bayou Sale 138 kV - WaxLake 138 kV	Yes	
CLEC	Coughlin 138 kV - Plaisance 138 kV	Yes	Yes
CLEC	Teche 138 kV - Bayou Sale 138 kV	Yes	
CLEC	WaxLake 138 kV - El Paso Tap 138 kV	Yes	
XEL	La Crosse 69.0 kV - West Salem 69.0 kV	Yes	Yes
EES-EMI	Franklin 500 kV - Bogalusa 500 kV	Yes	
EES-CLEC	Plaisance 138 kV - Champagne 138 kV	Yes	
GRE	Maple Lake 69 kV - Annandale 69 kV	Yes	
EES-EMI	Lakeover 500 kV- Lakeover 115 kV	Yes	
DEO&K	Todd Hunter 345 kV - Todd Hunter 138 kV (15)	No	
DPC	Lublin Tap 69 kV - Lakehead 69 kV	No	
DPC	Rochester 161 kV - Wabaco 161 kV	No	
EES	Little Gypsy 115 kV - Claytonia 161 kV	No	
EES-EMI	Batesville 230 kV - Batesville 115 kV	No	
LGEE	Ghent 138 kV - North American Stainless 138 kV	No	
METC	Campbell 138 kV - Northern Fibre 138 kV	No	
METC	Lewiston 69.0 kV - Atlanta Distribution 69.0 kV	No	
METC	Gaylord OCB 69.0 kV - Johannesburg Jct 69.0 kV	No	
METC	Johannesburg Jct 69.0 kV - Lewiston 69.0 kV	No	
MP	Substation 16L Tap 115 kV - Cotton Tap 115 kV	No	
MP	Cotton Tap 115 kV - Bergen Lake Tap 115 kV	No	
SIGE	Northwest 69 kV - Pigeon Creek 69 kV	No	
SIPC	Grassy 69.0 kV - Hastings 69.0 kV	No	
SIPC	Marion Power Plant 69.0 kV - Grassy 69.0 kV	No	
SIPC	Marion Power Plant 69.0 kV -	No	
SIPC	Marion Power Plant 69.0 kV - Double Circuit 69.0 kV	No	
SIPC	Double Circuit 69.0 kV - Creal Springs 69.0 kV	No	
SMEPA	Prentiss 161 kV - Prentiss 69 kV	No	
TVA	Batesville 115 kV - Star 115 kV	No	
TVA	Star 115 kV - Batesville 161 kV	No	
UPPC	Victoria Falls 69 kV - Rockland Jct 2	No	
UPPC	Victoria Falls 69 kV - Rockland Jct 1	No	
UPPC	Rockland Jct 2 69 kV - Rockland 69 kV	No	
UPPC	Rockland Jct 1 69 kV - UPPS Co 69 kV	No	
UPPC/MIUP	Rockland 69 kV - MASS 69 kV	No	

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
XEL	Black Dog 115 kV - Wilson Tap 115 kV	No	
XEL	Henderson 69 kV - Jessen Land 69 kV	No	
XEL	Winthrop 69.0 kV - Winthrop 69.0 kV	No	
XEL	Eagle Lake 69.0 kV - Jamestown Tap 69.0 kV	No	
XEL	Kelso Switching Station 69.0 kV - Henderson 69.0 kV	No	
XEL	Fort Ridgly 69 kV - Schiling Tap 69 kV	No	
XEL	Johnson Tap 69 kV - Penelope 69 kV	No	
XEL	Eagle Lake 69.0 kV - Eagle Lake 69.0 kV	No	
XEL	Traverse 69 kV - New Sweden Tap 69 kV	No	
XEL	Lake Marion Tap 69 kV - ELKO 69 kV	No	
ALTW	Burlington - South Burlington 69 kV	No	
ALTW	4th Street - Agency 69 kV	No	
ALTW	South Burlington - 4th Street 69 kV	No	
CE	Wemple Town 345 - Wemple town 138 kV	No	
CE	Wemple Town 138 - Wemple town 138 kV	No	

Table 4.5-2: MTEP16 long-term constraints that limit deliverability of about 1,800 MW of Network Resources

MTEP16 Mitigation

MTEP16 near-term (five-year) summer peak deliverability analysis results showed four constraints that require mitigation as previously seen in table 4.5-1. Mitigation was submitted for each of these constraints to alleviate limitation. Table 4.5-3 shows the project provided for each of the four constraints requiring mitigation.

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

Table 4.5-3: MTEP16 projects submitted to alleviate constraints that limit deliverability of Network Resources[31]

.

[31] **Note:** Any mitigation stated as (TBD), already has verbal mitigation submitted and its project submission is pending at this moment

MTEP15 Mitigation

MTEP15 analysis results show a total of about 3,530 MW of deliverability is restricted due to constraints in the MTEP15 near-term scenario under MISO functional control and an additional 210 MW is restricted due to constraints identified on non-transferred transmission facilities and facilities subject to MISO Agency Agreement.

Table 4.5-4 shows projects submitted to alleviate constraints observed in MTEP15 results.

Overloaded Branch	Area	MW Restricted	Mitigation (MTEP ID)
Nelson – Michigan 230 kV	351 EES	1034.8	10008
Verdine – PPG 230 kV	351 EES	1034.8	10008
Grimes – Mt. Zion 138 kV	351 EES	98.19	9852
Grimes 345/138 kV transformer - 2	351 EES	93.88	9852
Grimes 345/138 kV transformer - 1	351 EES	84.69	9852
Mt. Zion – Line 558 Tap 138 kV	351 EES	28.71	9852
Tubular – Dobbin 138 kV	351 EES	22.73	9821
Grimes – Bentwater 138 kV	351 EES	15.11	9852
Cahokia 345 kV Bus 1 – Cahokia 138 kV Bus 4	357 AMIL	257.88	9719

Table 4.5-4: MTEP15 projects submitted to alleviate constraints that limit deliverability of Network Resources

Proposed Changes for MTEP17

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

Changes proposed for MTEP17 are:

- Energy Resource with Transmission Service Requests mitigation will be specifically identified
- The Top 30 list will assign placeholders on a plant basis rather than unit basis
- Base dispatch will not exceed the sum of the dispatch on a local balancing authority (LBA) basis

Energy Resource with Transmission Service Requests mitigation will be specifically identified. Transition deliverability studies identified deliverable MWs and the remaining were allocated to the non-deliverable bucket. Through transitional studies, MISO emphasized no loss of transmission service. In MTEP16 and previous years the TSRs were included in the base case. Mitigation was not directly identified within Baseline Generator Deliverability process. In MTEP17 constraints identified due to Energy Resources with Transmission Service Requests will require mitigation. The change is being made to ensure that services granted are kept whole concurrently.

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

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

4.6 Long-Term Transmission Rights Analysis Results

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

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

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

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

For 2016-2017 planning year, the total LTTR payment is $351 million. The LTTR infeasibility uplift ratio is 3.97 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	$351	$13.9	3.97%

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2016 Annual ARR Allocation

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

Planned mitigations associated with limited LTTR feasibility are listed in Table 4.6-2. Binding constraints are filtered for those with values greater than $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 MTEP16 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2016	Fall 2016	Winter 2016	Spring 2017	Grand Total	Planned Mitigation
ANO-PLEASANT HILLS 500 FLO ANO-MABELVALE 500	$175,232.84	$193,371.55	$286,966.89	$644,074.33	$1,299,645.61	P8041: Upgrade Terminal Equipment; ISD May 10, 2017
SHRAM TAP-MIDWAY 138 FLO KINCAID-PANA-COFFEEN 345+KINCAID UNIT 1-SPS	$178,756.93	$283,092.69	$137,608.28	$198,315.15	$797,773.05	P7846, MTEP16 Target B; ISD June 2018
Bush-Lafayette 138 FLO WESTWOOD-CONCORD-SOUTHEAST 138	$-	$-	$112,419.02	$602,281.87	$714,700.89	
MARBLEHEAD N 161/138 kV T1 FLO MEPPEN-S QUINCY 138	$231,718.31	$421,243.83	$-	$-	$652,962.14	
REYNOLDS-MAGNET 138 kV FLO DEQUINE-WESTWOOD 345 1	$-	$563,339.29	$-	$-	$563,339.29	
NEWTON-ROBINSON 138 FLO NEWTON-CASEY W 345	$453,431.24	$-	$-	$-	$453,431.24	P7800, MTEP15 Appendix A; ISD December 2015
E QUINCY-HAMILTON 138 FLO PALMYRA - MARBLEHEAD N 161	$192,186.54	$141,958.86	$46,256.61	$42,375.22	$422,777.23	P9736, MTEP16 Target A; ISD May 2016
NEWTON 345/138 kV TR 1 FLO NEWTON-CASEY W 345	$-	$-	$365,348.01	$-	$365,348.01	P9724, Appendix B; ISD June 2018

Constraint	Summer 2016	Fall 2016	Winter 2016	Spring 2017	Grand Total	Planned Mitigation
LAYFIELD - HARTBURG 500 FLO GRIMES - CROCKET 345	$182,589.25	$93,491.89	$807.28	$27,099.91	$303,988.33	Stability limit increased to 1,525 MVA in March 2016
EUGENE - CAYUGA 345 FLO ROCKPORT-JEFFERSON 765	$-	$-	$-	$230,381.09	$230,381.09	
GRIMES - MT ZION 138 FLO ELDORADO - MT OLIVE 500	$55,995.24	$-	$14,523.58	$129,600.30	$200,119.12	10487: Western Region Economic Project; ISD June 2020

Table 4.6-2: Infeasible Uplift Breakdown by Binding Constraints from the 2016 Annual FTR Auction

Chapter 5

Economic Analysis

2016

5.1 Economic Analysis Introduction

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

The MISO Value-Based Planning Process ensures transmission expansion plans minimize the total electric costs to consumers, maintain an efficient market, and enable state and federal public energy policy — all while maintaining system reliability. The Multi-Value Project Portfolio, approved in MTEP11, demonstrates the success of the Value-Based Planning Process. The Multi-Value Projects will save Midwest energy customers more than $1.2 billion in projected annual costs and enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals.[32]

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.

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

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

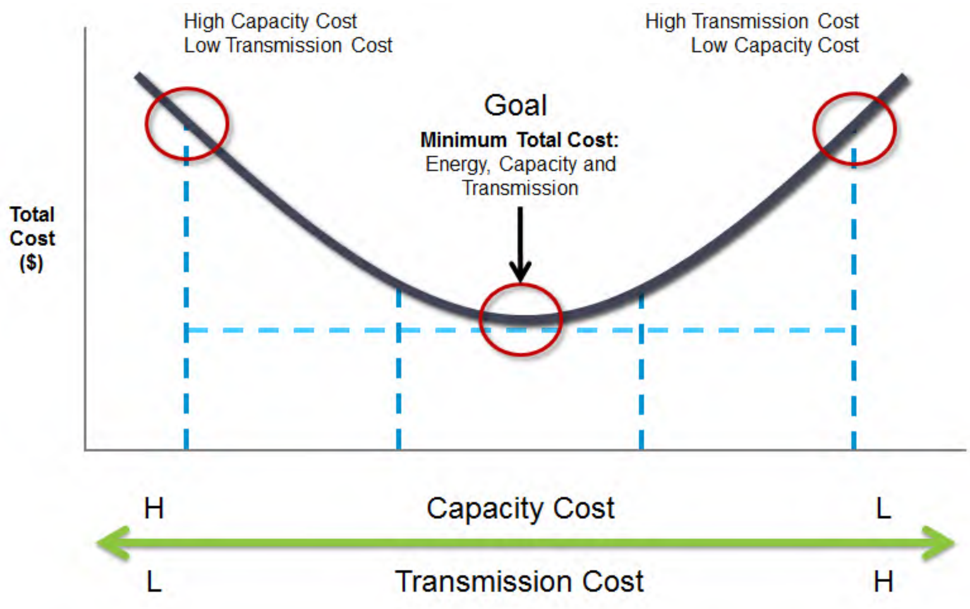


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

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

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

Value-Based Planning Process

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

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

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

MISO's Value-Based Planning Process is also known as the Seven-Step Planning Process (Figure 5.1-2). While the Value-Based Planning Process is chronologically sequenced, not all projects start at Step 1 and end at Step 7. For example, depending on scope, a project may begin with pre-existing assumptions or plans and therefore start in Steps 3, 4, 5 or 6. 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.

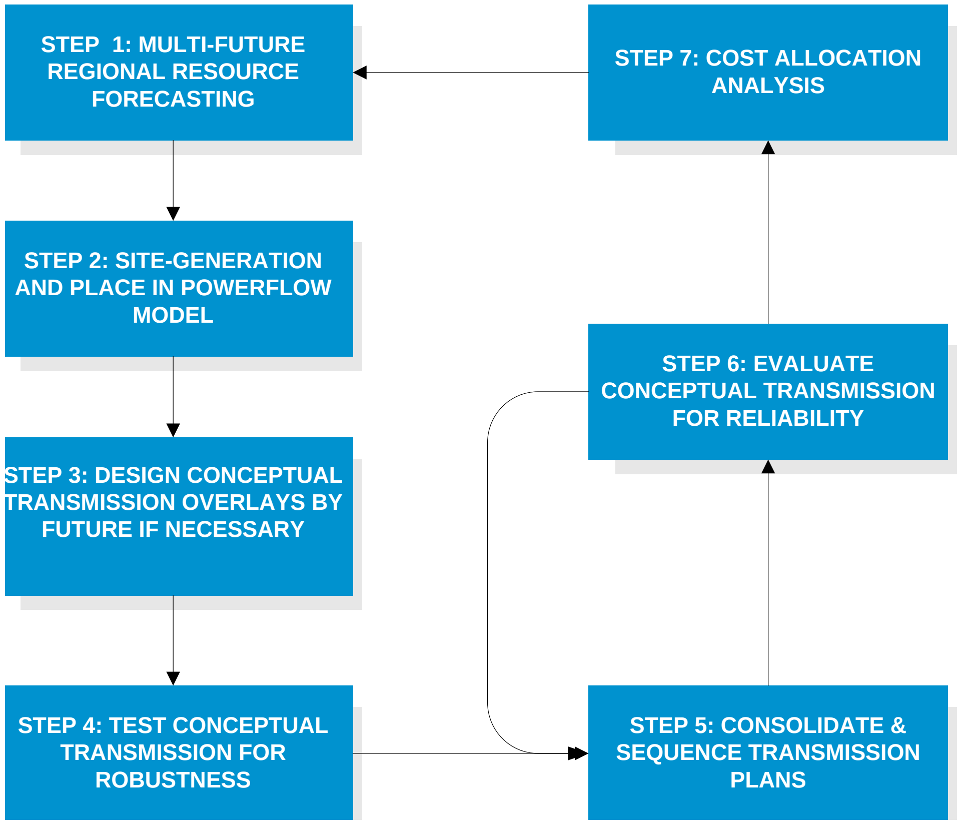


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

Step 1: Futures Development and Regional Resource Forecasting

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

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

A more detailed discussion of the assumptions and methodology around the MTEP16 future scenarios is in Chapter 5.2: MTEP Future Development.

Step 2: Siting of Regional Resource Forecast Units

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 MTEP16 future is in Chapter 5.2: MTEP Future Development.

Step 3: Design Conceptual Transmission By Future

With initial forecasts developed in Steps 1 and 2, economic potential outputs from the planning models become a road map to design conceptual transmission for each future scenario. Economic potential information identifies both the location and the magnitude of effective transmission expansion potential. Economic potential information includes but is not limited to:

- Source and sink plots
- Locational marginal price forecasts
- Historical and forward-looking congestion reports
- Optimal incremental interface flows

Conceptual transmission designs by future consider both MISO-identified regional projects as well as local projects identified by Transmission Owners. Combining regional and local projects, transmission expansion plans can be designed and analyzed to find the optimal balance point between local and regional development for each MTEP future scenario.

The conceptual transmission design process using economic potential information is shown in Chapter 5.3: Market Congestion Planning Study.

Step 4: Test Conceptual Transmission For Robustness

Through Step 3 of the process, transmission plans are developed for each future scenario in isolation of other future scenarios or plans. The ultimate goal of Step 4's robustness testing is to develop one transmission expansion plan capable of accommodating the various uncertainties inherent to potential policy outcomes and that can perform reasonably well under a broad set of future scenarios. To perform robustness tests, each preliminary transmission plan is assessed under all of the future scenarios. The plan emerging from this assessment with the highest value, most flexibility and lowest risk will be selected to move forward as the best-fit solution.

Step 5: Consolidate and Sequence Transmission

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

Step 6: Evaluate Conceptual Transmission For Reliability

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. 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.

Step 7: Cost Allocation

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
Participant Funded (Other)	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 by requestor (local zone(s))
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
Baseline Reliability Project	NERC Reliability Criteria	100 percent allocated to local Pricing Zone
Market Efficiency Project	Reduce market congestion when benefits exceed costs by 1.25 times	Distributed to Local Resource Zones commensurate with expected benefit; 345 kV and above 20 percent postage stamp to load
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	100 percent postage stamp to load

Table 5.1-1: Summary of MISO Cost Allocation mechanisms

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

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

In MTEP16, MISO's Value-Based Planning Process is exemplified in the MTEP Future Development (Chapter 5.2), and Market Congestion Planning Study (Chapter 5.3).

5.2 Futures Development

The MTEP16 generation expansion results created in 2015 cover both the North/Central and South regions. MISO completed this assessment of generation using the Electric Generation Expansion Analysis System (EGEAS) model in 2015. Using assumptions developed in coordination with the Planning Advisory Committee (PAC), MISO developed these models to identify the least-cost generation portfolios needed to meet the resource adequacy requirements of the system for each future scenario.

Detailed MTEP16 capacity expansion results are presented in Appendix E2[33].

Capacity Expansion Results

The study determined the aggregated, least-cost capacity expansions for each defined future scenario through the 2030 study year (Figure 5.2-1). This added capacity is required to maintain planning reliability targets for each region as well as identify other economic generation. This iteration of MTEP shows a long-term drive toward economically selected renewables in carbon cost futures and an increase in retirements and gas consumption. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

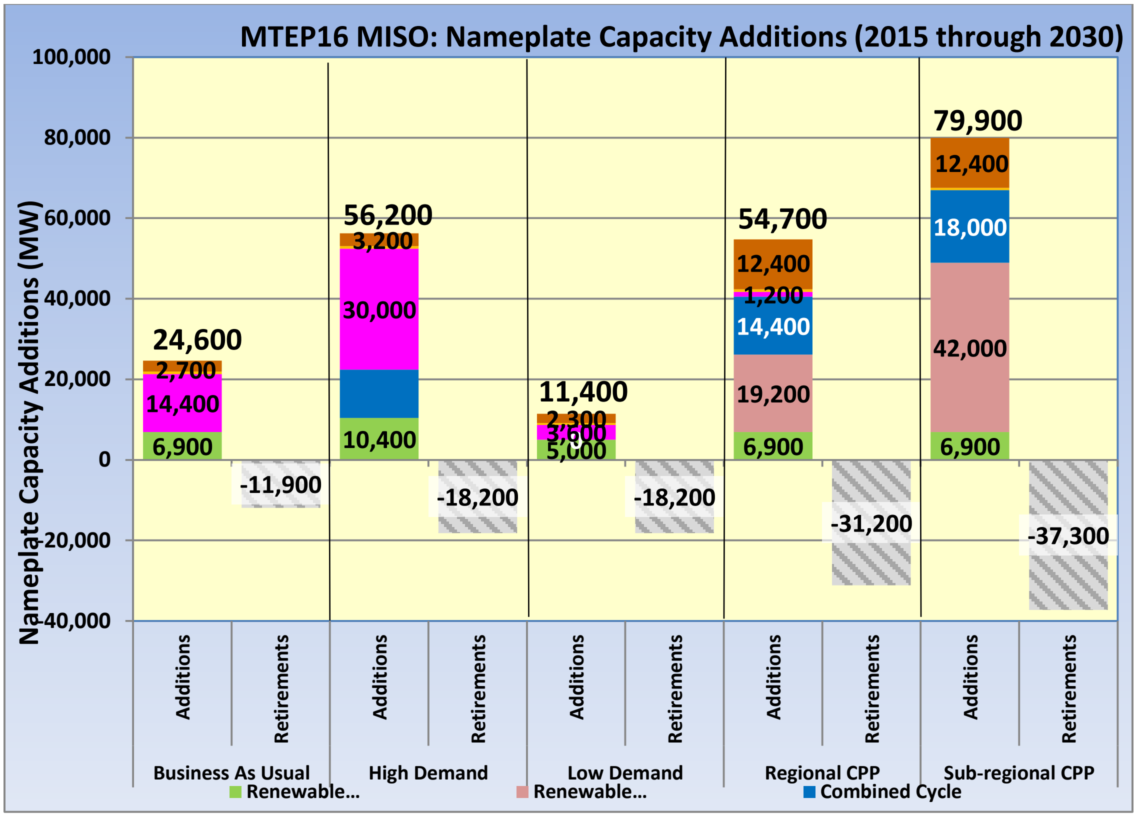


Figure 5.2-1: MISO nameplate capacity additions by future (2015-2030 EGEAS Model)[34]

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[33] Futures were developed prior to the stay of the clean power plan. Futures under development for MTEP 17 will reflect a broader range of portfolio changes not specifically tied to the Clean Power Plan.

The Business As Usual future projects 24.6 GW of additional capacity to maintain system reserves and replace retired capacity between 2015 and 2030. MISO, with advice from the PAC, models 12.6 GW of coal retirements as a minimum in all future scenarios[35] to represent the projected effects of EPA regulations, specifically, Mercury and Air Toxics Standards (MATS). The High Demand and Low Demand futures include additional age-related retirements of non-coal and non-nuclear resources. On top of the age-related and 12.6 GW of coal retirements, the Regional and Sub-Regional Clean Power Plan (CPP) futures include an additional 14 GW and 20 GW of coal retirements respectively. Future capacity expansions include demand response (DR) and energy efficiency (EE) programs, as well as natural gas combustion turbines, natural gas combined cycle units, wind and solar.

Futures Development

Scenario-based analysis provides the basis for developing economically feasible transmission plans for the future. A future scenario is a stakeholder-driven postulate of what could be. This determines the non-default model parameters (such as assumed values) driven by policy decisions and industry knowledge. With the increasingly interconnected nature of organizations and federal interests, forecasting a range of plausible futures greatly enhances the planning process for electric infrastructure. The futures development process provides information on the cost-effectiveness of environmental legislation, wind development, demand-side management programs, legislative actions or inactions and many other potential scenarios.

Future scenarios and their associated assumptions are developed with high levels of stakeholder involvement. As a part of compliance with the FERC Order 890 planning protocols, MISO-member stakeholders are encouraged to participate in PAC meetings to discuss transmission planning methodologies and results. Scenarios are regularly developed to reflect items such as shifts in energy policy, changing demand and energy growth projections, and/or changes in long-term projections of fuel prices. Previously, future scenario definitions were developed annually; however, several prior iterations of MTEP saw very similar futures with gas price and load growth variations year over year. Rather than continue to develop similar futures, MISO will implement a new futures process beginning with MTEP17[36]. Under the new process, futures will be evaluated annually and a decision made with input from stakeholders as to whether futures need to be wholly redesigned or merely updated with current fuel and demand forecasts.

Five narratives describe the MTEP16 future scenarios and their key drivers:

- The baseline, or Business as Usual (BAU), future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. All applicable EPA regulations governing electric power generation, transmission and distribution are modeled. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into the Module E Capacity Tracking (MECT) tool. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource

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

[35] MISO performed an EPA impact analysis study in 2011 in order to determine the potential of coal fleet retirements. The EPA analysis produced three levels of potential coal retirements: 3 GW, 12.6 GW and 23 GW. To capture these potential retirements in the scenario-based analysis, MISO analysts, in conjunction with the Planning Advisory Committee (PAC), chose to model a minimum of 12.6 GW of retirements in all futures, with the exception of 23 GW of retirements being modeled in the Environmental future.

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

Standard (EERS) mandates are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled.

- The High Demand future captures the effects of increased economic growth resulting in higher energy costs and medium-high gas prices. The magnitude of demand and energy growth is determined by using the upper bound of the Load Forecast Uncertainty metric and also includes forecasted load increases in the South region. All current state-level RPS and EERS mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution are incorporated. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional age-related retirements are captured using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
- The Low Demand future captures the effects of reduced economic growth resulting in lower energy costs and medium-low gas prices. The magnitude of demand and energy growth is determined by using the lower band of the Load Forecast Uncertainty metric. All current state-level RPS and EERS mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional, age-related retirements are captured using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
- The Regional Clean Power Plan future focuses on several key items from a footprint-wide level that, in combination, result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include:
    - Capturing expected effects of existing environmental regulations on the coal fleet, with 12.6 GW of coal unit retirements modeled, including known or announced retirements
    - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in significant carbon emissions reduction by 2030
    - Additional, age-related retirements using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric
    - An economic maturity curve with solar and wind to reflect declining costs over time
    - Demand and energy growth rates modeled at levels as reported in Module E
- The Sub-Regional Clean Power Plan future focuses on several key items from a zonal or state level, which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include:
    - The capture of expected effects of existing environmental regulations on the coal fleet, with 12.6 GW of coal unit retirements are modeled, including existing or announced retirements
    - 20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in a significant reduction in carbon emissions by 2030
        - These increased retirements and carbon cost levels from the Regional CPP Future are consistent with regional/sub-regional CPP assessments performed by MISO and other organizations since the CPP’s introduction

- Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric
- An economic maturity curve with solar and wind to reflect declining costs over time
- Demand and energy growth rates modeled at levels as reported in Module E

These future scenarios were developed and approved prior to the current 111(d) rule. The EPA finalized this rule on October 23, 2015[37] and it was stayed by the U.S. Supreme Court in on February 9, 2016.

Effective Demand and Energy Growth Rates

Many states have encouraged, and in some cases mandated, the use of demand-side management (DSM) technologies in order to reduce the need for investment in new power generation. To evaluate the potential of DSM within the footprint, MISO consulted with Global Energy Partners LLC in 2010. This effort led to the development of 20-year forecasts for various types of DSM for the MISO region and the rest of the Eastern Interconnection. The study found DSM programs have the potential to significantly reduce the load growth and future generation needs of the system.

For MTEP16, the DSM program's magnitudes were scaled to reflect state-level energy efficiency and/or demand response mandates and goals. To calculate the effective demand and energy growth rates, which are ultimately input into the production cost models, MISO nets out only the impact of the energy efficiency programs from the baseline demand and energy growth rates. The resulting growth rates for the various futures range from 0 percent to 1.43 percent for demand and 0.11 percent to 1.53 percent for energy (Table 5.2-1). Demand response programs are modeled within the production cost simulations as oil-fired generators with a significantly high fuel cost when compared to other generators.

	Baseline Growth Rates		Effective Growth Rates	
Future Scenarios	**Demand**	**Energy**	**Demand**	**Energy**
Business as Usual	**0.75%**	**0.82%**	**0.65%**	**0.76%**
High Demand	**1.55%**	**1.61%**	**1.43%**	**1.53%**
Low Demand	**0.11%**	**0.19%**	**0.00%**	**0.11%**
Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**
Sub-Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**

Table 5.2-1: MTEP16 effective demand and energy growth rates

Production and Capital Costs

EGEAS capacity expansion data provides the present value of production and capital costs for the study period through 2030 (Figure 5.2-2). While EGEAS does not model transmission congestion, the results nonetheless demonstrate scenarios in which higher or lower production costs could be incurred when

[37] https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

compared to a Business as Usual-type scenario. Production costs include fuel; variable and fixed operations and maintenance; and emissions costs (where applicable). As stated, EGEAS does not model congestion, therefore does not capture those costs or costs for transmission expansion. Gas line expansion is also outside of this analysis. Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and RPS requirements that drive the future capacity expansion capital investments and total production costs.

Due to the significantly higher production costs in the CPP futures, it should be noted that approximately $64 billion of the total $348 billion in production costs are due to the $25/ton carbon tax modeled in the Regional CPP future, while in the Sub-Regional CPP future approximately $90 billion of the total $431 billion in production costs are due to the $40/ton carbon tax modeled. Also, the retirement of an additional 14 GW and 20 GW of coal units on top of the 12.6 GW leads to higher production costs resulting from higher capacity factors of gas-fired generation, which has a higher-modeled fuel price than coal.

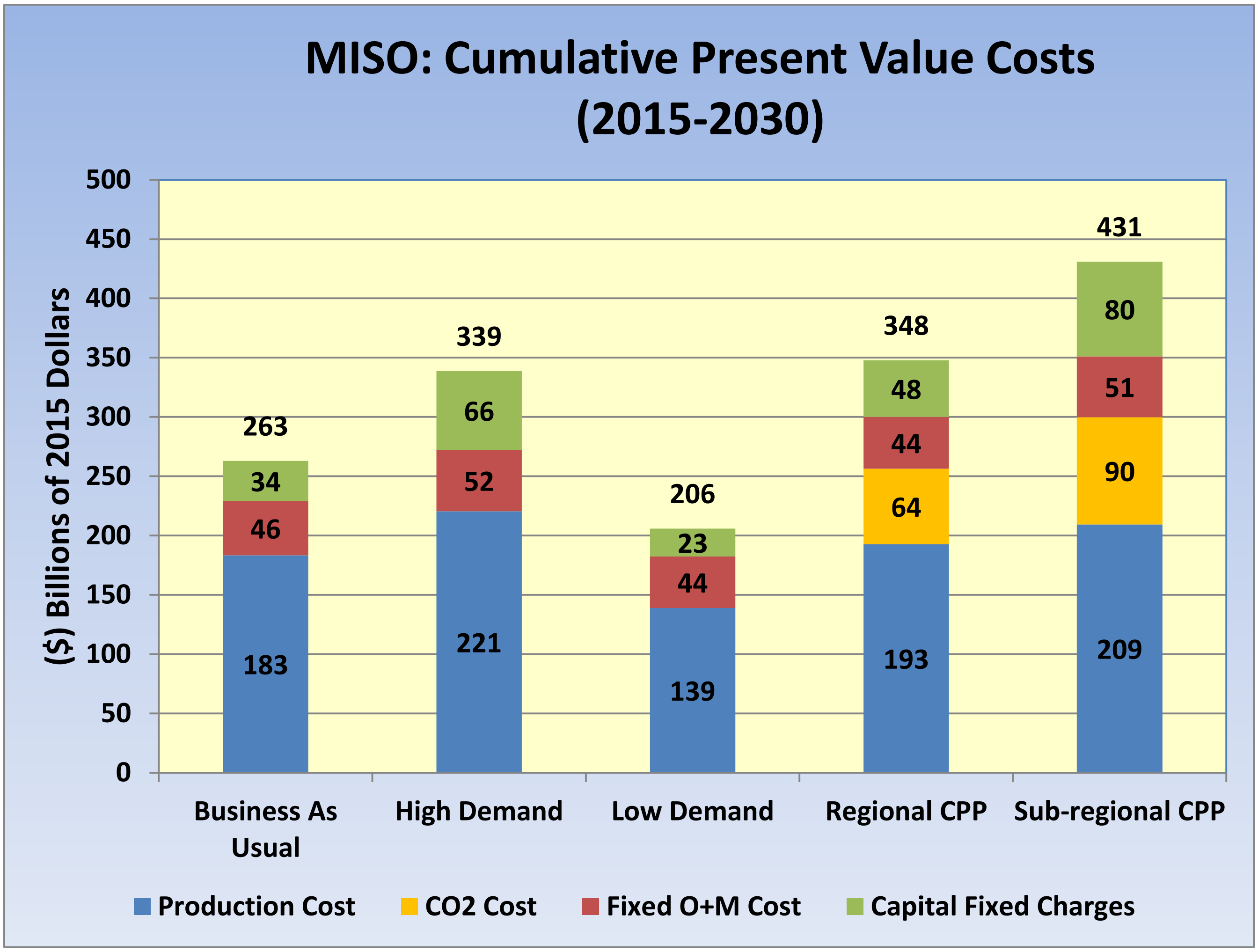


Figure 5.2-2: MISO present value of cumulative costs in 2015 U.S. dollars

Natural Gas Fuel Price Forecasting

Accurate modeling of future natural gas prices is a key input to the MTEP planning process. While natural gas prices have remained relatively low over the past few years, prices have reached well over $10/MMBtu as recently as 2008. Therefore, it is important to capture a wide range of forecasts to account for potential volatility. For MTEP16, MISO utilized a natural gas forecast developed by Bentek[38] as a baseline. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. The five scenario-specific MTEP16 natural gas forecasts are shown in nominal dollars per MMBtu (Figure 5.2-3).

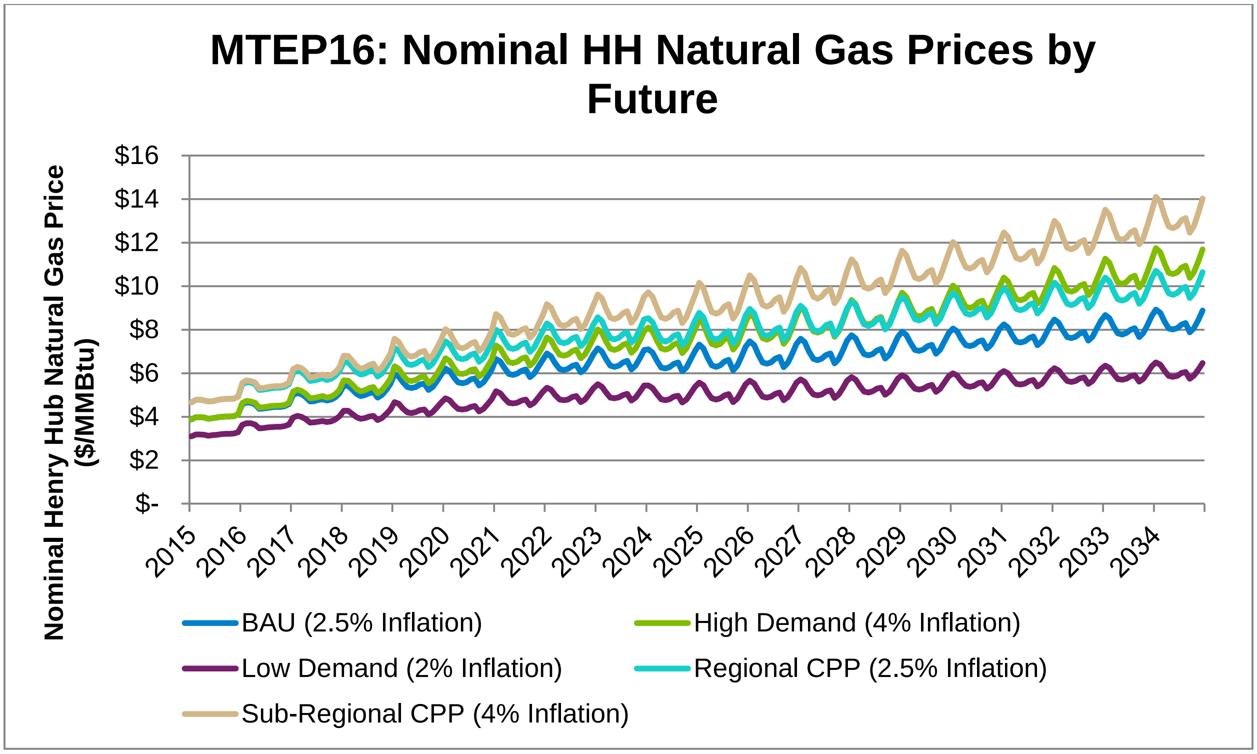


Figure 5.2-3: Natural gas forecasts by future

Renewable Portfolio Standards

Several states in the MISO footprint have some form of state mandate or goal to provide a specified amount of future energy from renewable resources. The Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE) provides a breakdown of each state's mandate or goal. MISO uses the DSIRE information to calculate future penetrations of renewables, which are assumed to be primarily wind and solar, in each of the MTEP futures (Table 5.2-2). The MTEP16 Business as Usual, High Demand and Low Demand futures model state-mandated wind and solar only. In addition to modeling a minimum of state-mandated wind and solar, the Regional CPP and Sub-Regional CPP futures model renewable maturity cost curves, with solar declining at a rate of 10 percent per year for five years and wind declining at a rate of 1 percent per year for five years.

[38] See Table 5-4 of the Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis Report. https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Phase%20III%20Gas-Electric%20Infrastructure%20Report.pdf

Future Scenario	MISO Incremental Wind Penetration	MISO Incremental Solar Penetration	Percentage of Energy from All Renewable Resources in 2030
Business As Usual	5,400 MW	1,500 MW	12%
High Demand	8,700 MW	1,700 MW	12%
Limited Demand	3,600 MW	1,375 MW	12%
Regional CPP	5,400 MW	20,700 MW	16%
Sub-Regional CPP	25,800 MW	23,100 MW	26%

Table 5.2-2: MISO wind and solar penetrations (including those with signed Generation Interconnection Agreements through 2030)

Carbon Emissions

Each future scenario includes a different resource mix and thus produces a different carbon dioxide output (Figure 5.2-4). For all futures, with the exception of the High Demand future, total CO_2 emissions decline or remain flat between 2015 and 2030. Coal plant retirements, in combination with increased levels of renewables and demand-side management programs, are key factors in allowing carbon emissions to decline.

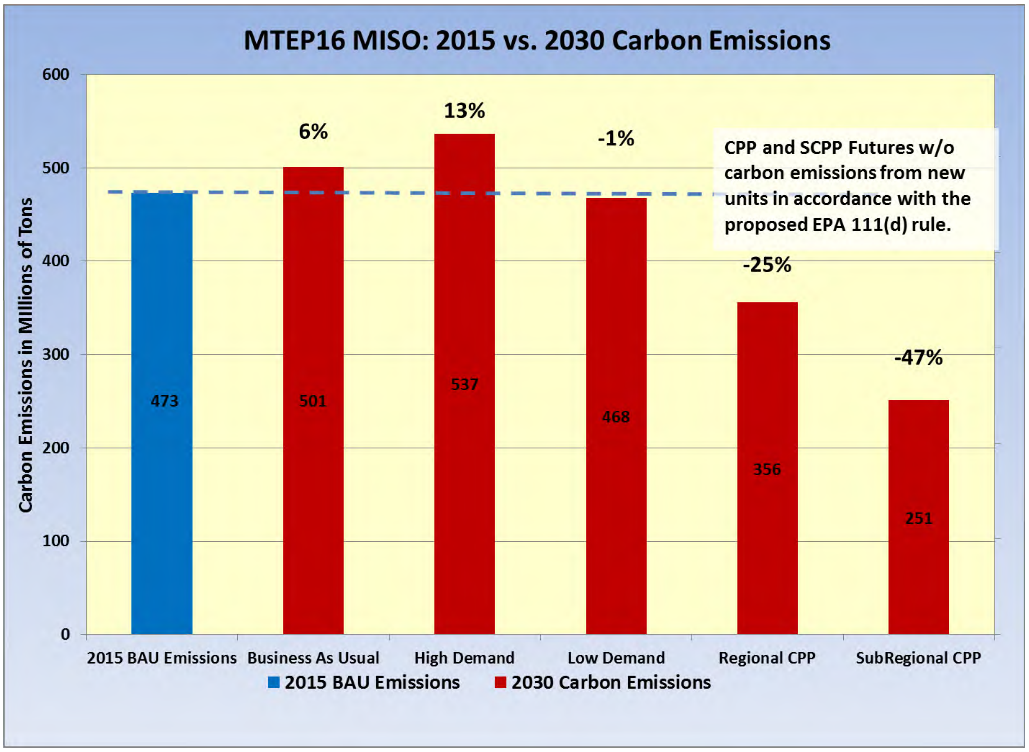


Figure 5.2-4: MISO carbon dioxide production

An alternative way of looking at carbon emissions is to investigate total CO_2 emissions per MWh of total annual energy (Figure 5.2-5). Coal retirements, coupled with increased renewable energy penetration, lead to declining rates of emissions in all MTEP scenarios. The sharpest decrease can be seen in the Regional CPP and SubRegional CPP Futures, which analyze the highest amount of coal unit retirements.

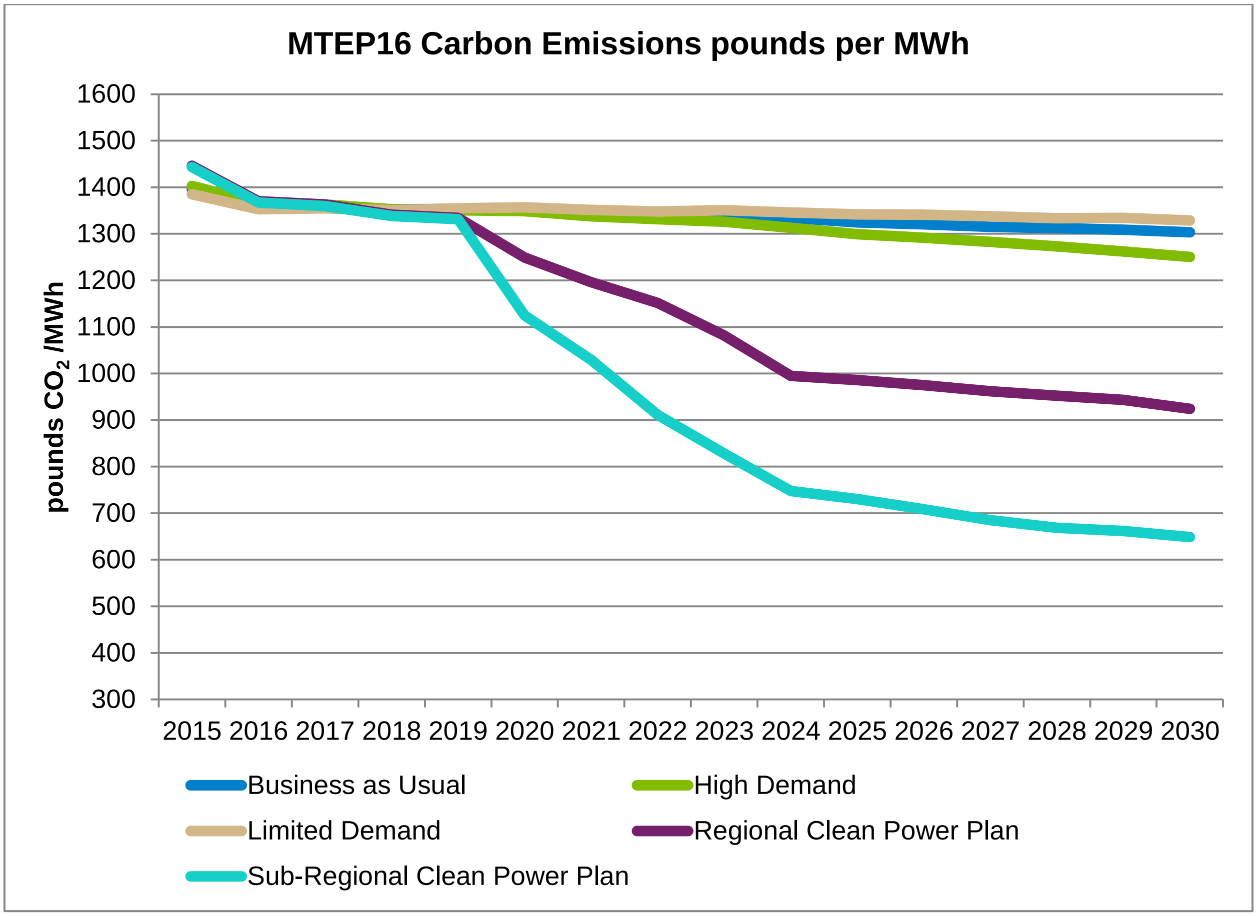


Figure 5.2-5: Carbon emissions per megawatt hour

Siting Of Capacity

Generation resources forecasted from EGEAS are specified by fuel type and timing, but these resources are not site-specific. The process requires a siting methodology tying each resource to a specific bus in the powerflow model and uses the MapInfo Professional Geographical Information System (GIS) software.

DR programs are sited at the top 10 load buses for each LSE in each state having a DR mandate or goal. The amount of DR remains constant across all futures. More detailed siting guidelines, methodologies and the results for the other futures are depicted in Appendix E2.

5.3 Market Congestion Planning Study

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

A consolidated economic planning effort has been undertaken for the MISO North/Central and South regions in MTEP16 in order to better align the study process across the MISO footprint.

Study Summary: MCPS North/Central Region

The 2016 MCPS study effort for the North/Central region identifies various congested flowgates and evaluates corresponding applicable transmission solutions. By building on the MCPS 2015 analysis, the 2016 cycle focuses on three specific areas that show the highest congestion: Iowa/Minnesota, Illinois, and Northern Indiana. In MTEP15, Duff to Coleman 345 kV was approved as a Market Efficiency Project (MEP) and addresses congestion near southern Indiana. Thus, southern Indiana did not have significant congestion and was not a focus area in MTEP16. Ultimately, the area with the most congestion, and therefore highest potential benefit, is on the border of Iowa and Minnesota.

MISO staff and stakeholders collaborated on the development of several solutions to mitigate congestion in various parts of the footprint. The solutions were tested for their robustness to address system needs under a wide variety of scenarios, embodied by the MTEP16 futures. Ultimately, solution I-2, a new Huntley to Wilmarth 345 kV circuit with an estimated cost range from $88 to $108 million, was found to offer the best value. This project completely mitigates the congestion on Huntley to Blue Earth 161 kV and strengthens the high-voltage power delivery system; thus, allowing for greater utilization of lower-cost generation to serve load. Furthermore, the project is found to be robust under all sensitivity analyses, including when wind projects in the MISO Generation Interconnection queue with a DPP or GIA-in-Progress status are modeled instead of RGOS/RRF wind in Iowa and Minnesota.

Subsequently, MISO recommends the Huntley to Wilmarth 345 kV project to the MISO Board of Directors for approval as a Market Efficiency Project (MEP) in MTEP16.

Study Summary: MCPS South Region

Since integration, the MISO Board of Directors has approved significant transmission investments in the MISO South region leading to a reduction in congestion. The 2016 MCPS study effort for the South region is built on the progress made during the MTEP15 cycle, which identified several congested flowgates and evaluated the applicable transmission solutions. The 2016 cycle focuses on five specific areas in MISO South: Amite South/Downstream of Gypsy (DSG), West of the Atchafalaya Basin (WOTAB)/Western, Local Resource Zone (LRZ) 8 (Arkansas), LRZ10 (Mississippi) and Remainder of LRZ9 (Rest of Louisiana).

In the MTEP16 MCPS study effort, several solutions were designed in a collaborative effort between MISO and stakeholders. The solutions were tested for their robustness to address system needs under a variety of scenarios, embodied by the MTEP16 futures. Ultimately, four projects were selected to address system needs observed in Amite South/DSG, Remainder of LRZ9 (Rest of Louisiana), LRZ10 (Mississippi), and LRZ8 (Arkansas). The following four project candidates are recommended as economic Other Projects to Board of Directors for MTEP16 approval:

- First economic Other Project geographically located in Southeast Louisiana is to construct a new 230 kV substation south of the existing Ninemile substation called Churchill and construct a new 230 kV transmission line connecting the existing Waterford 230 kV substation to Churchill 230 kV substation. Additionally, re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation. This economic Other Project provides additional benefits to Amite South and Down Stream of Gypsy (DSG) load pockets. This project provides an outlet and improves the import capability by 650 MW into the DSG load pocket. Also, it provides operational flexibility in the region during planned transmission and generation outages as well as accommodating the system for any future retirements. The project will also provide enhanced resilience to the area during extreme events such as hurricanes. The estimated cost of the project is $87.7 million. Note that, the new 230 kV substation and re-configuration of the existing 230 kV transmission facilities are also part of an existing MTEP16 Appendix B reliability project with MTEPID 10587.
- Upgrade the terminal equipment on the Minden to Sarepta 115 kV line with an estimated cost of $1.9 million
- Relocate the existing McAdams 500/230 kV autotransformer to Lakeover with an estimated cost of $6.7 million
- Rebuilding the existing Trumann to Trumann West 161 kV line with an estimated cost of $7.6 million. Note that, the rebuild of Trumann to Trumann West 161 kV is also identified as a baseline reliability project and is recommended as a reliability project for approval in MTEP16.

MCPS Study Process Overview

The MCPS begins with a bifurcated Need Identification approach to identify both near- and long-term transmission issues. The Top Congested Flowgate Analysis identifies near-term, more localized congestion while the longer-term Congestion Relief Analysis explores broader economic opportunities (Figures 5.3-1). Given the targeted focus of the MCPS 2016, emphasis was placed on the top congested flowgate analysis. The congestion relief analysis will be employed in future, broader-scoped planning studies.

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

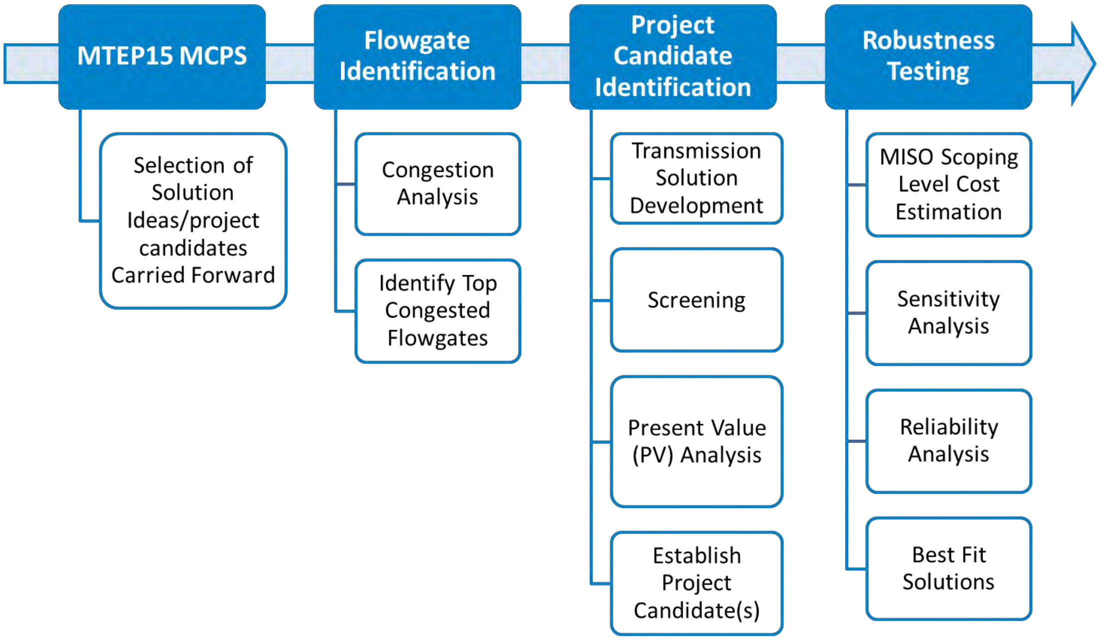


Figure 5.3-1: MCPS process overview

MISO Models and Futures

The production cost models utilized for this study are based on data from PROMOD Powerbase and the corresponding MTEP powerflow cases. The data is refreshed with the most current information and with the system variables (fuel cost, demand, etc.) reflecting the MTEP futures definitions. The agreed-upon future scenarios and weightings for the MTEP16 MCPS study are:

- Business as Usual (BAU): 19 percent
- High Demand (HD): 10 percent
- Low Demand (LD): 16 percent
- Regional CPP (RCPP): 30 percent
- Sub-Regional CPP (SRCPP): 25 percent

The Planning Advisory Committee (PAC) assigned weights to each future as a reflection of the perceived probability of each future being actualized (see Chapter 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 and forecasted congestion. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams (Figures 5.3-2 and 5.3-3).

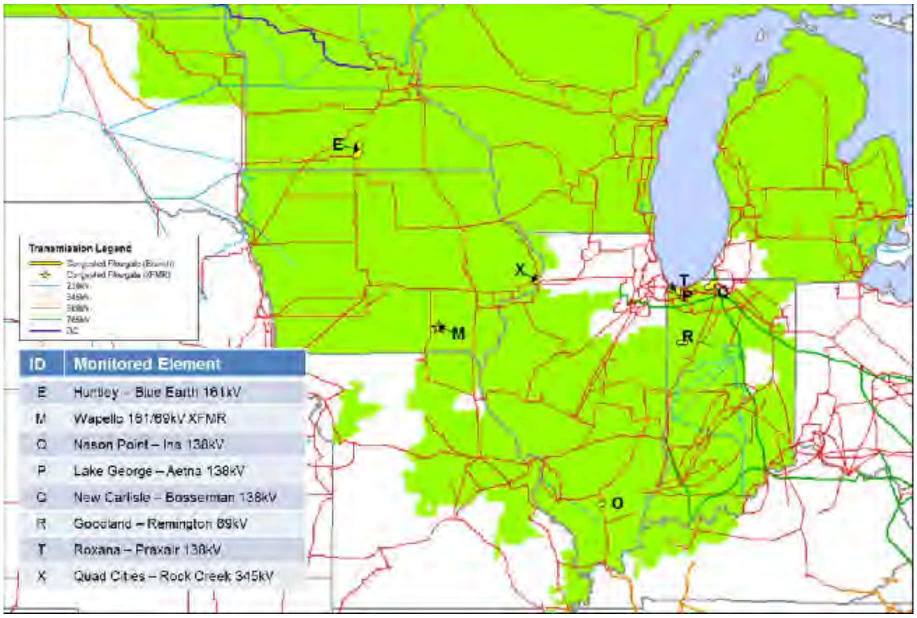


Figure 5.3-2: Projected Top Congested Flowgates in MISO North/Central Region

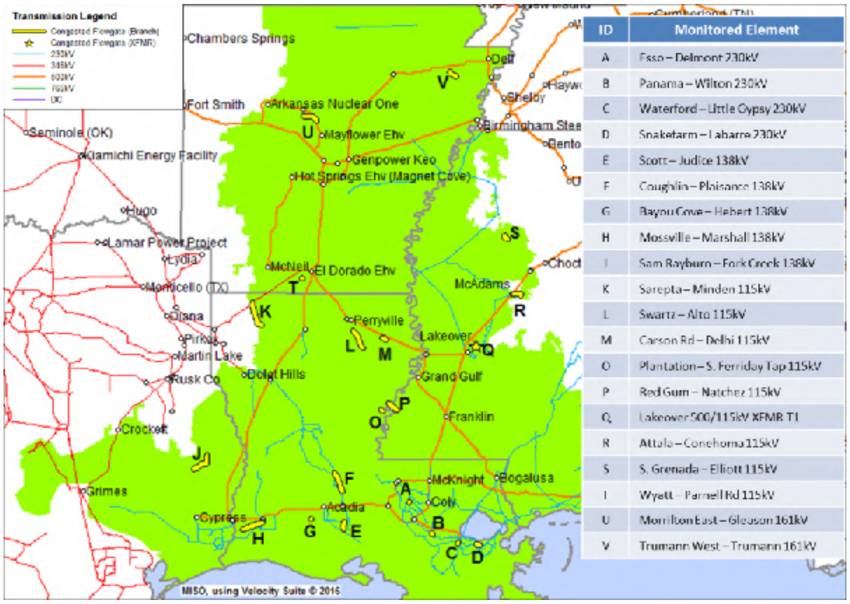


Figure 5.3-3: Projected Top Congested Flowgates in MISO South Region

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

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

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

Project Candidate Identification

Project candidate identification is a partnership between MISO and stakeholders to identify network upgrades that address the top congested flowgates. Solutions 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.

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

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

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

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

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

Robustness Testing

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

Project Benefit and Cost Analysis:

The MISO Tariff measures a MEP's benefit by the APC savings realized through the project under each of the MTEP future scenarios. APC savings are calculated as the difference in total production cost adjusted for import costs and export revenues with and without the proposed project in the transmission system. Given the five-year transition period following MISO South integration in 2013, the benefits for each project are counted only for the relevant MISO sub-region, North/Central or South. Data from three simulation years (2020, 2025 and 2030) are used as the basis for evaluating the project impact. A 20-year benefit is calculated by linearly interpolating and extrapolating from these three years. The total project benefit is determined by calculating the present value (PV) of annual benefits for the multi-future and multi-year evaluations.

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

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

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

Reliability Analysis:

The reliability analysis uses a no-harm test to determine the impact of project candidates on the thermal and voltage stability of the system under select NERC Category B and C contingencies. 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.

The no-harm test is performed on the following cases:

- Five-year-out Summer Peak
- Five-year-out Shoulder Peak with 40 percent wind
- Five-year-out Shoulder Peak with 90 percent wind (for North/Central region project candidates only)
- 10-year-out Summer Peak (for South region project candidates only)

The following NERC categories of contingencies are evaluated:

- Category P0 when the system is under normal conditions
- Category P1 contingencies resulting in the loss of a single element
- Category P2 contingencies resulting in the loss of two or more elements due to a single event

Iowa/Minnesota

A significant amount of congestion was identified on Huntley to Blue Earth 161 kV (Figure 5.3-8), which is near the border of Iowa and Minnesota. There are multiple factors contributing to the congestion on this line - one of which is the large amount of wind capacity and low-cost coal generation in northern Iowa. Further worsening congestion is the increase in wind capacity in Iowa that is assumed over the next 15 years. Finally, expected coal retirements near the Minneapolis/Saint Paul area such as Sherco 1, Sherco 2, and Clay Boswell 3 tend to increase the need for power to flow from northern Iowa to the Twin Cities via the Lakefield to Wilmarth 345 kV path. As a result, for the loss of this high-voltage transmission path, the low-voltage parallel path of Huntley to Blue Earth 161 kV becomes congested.

Congestion is also identified on the Wapello 161/69 kV transformer (Figure 5.3-8). Similar to Huntley to Blue Earth 161 kV, this transformer congests as a result of wind and coal in southern Iowa attempting to serve load centers near the border of Iowa and Illinois.

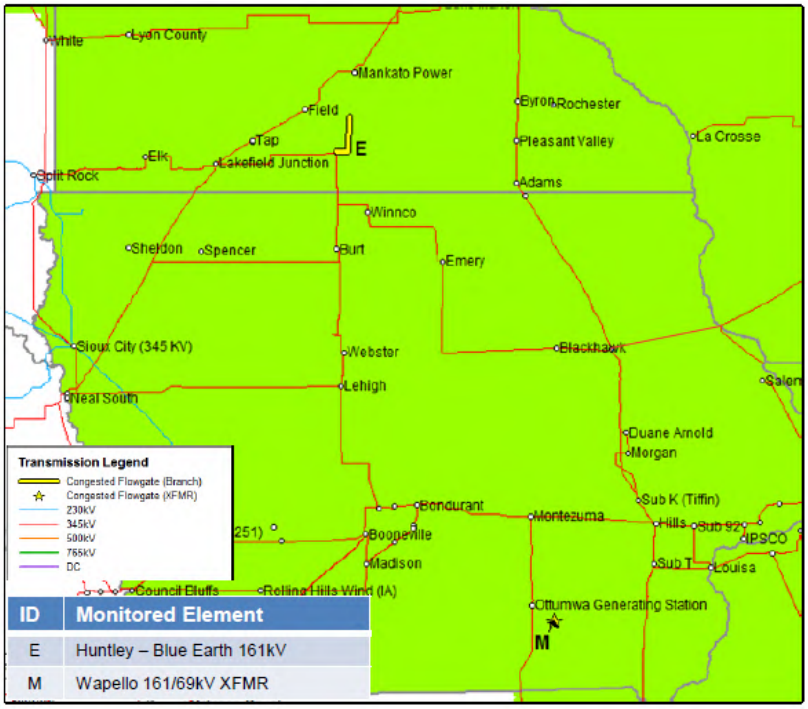


Figure 5.3-8: Iowa/Minnesota Top Congested Flowgates

Twenty-three solutions were evaluated in the Iowa/Minnesota area and 16 of those passed the screening analysis. All solutions that passed screening sought to address the congestion on Huntley to Blue Earth 161 kV and overlapped in their design elements. These solutions were divided into four groups based on similarities in their voltage level and the approach used in relieving congestion. Four solutions, one from each group, were selected for PV analysis due to their high screening index values. These solutions were:

- I-2: Huntley to Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)
- I-12: Huntley to NROC 345 kV new circuit
- I-15: Huntley to South Bend 161 kV reconductor, South Bend to Wilmarth 161 kV new circuit; Wilmarth substation 161 kV expansion with a 345/161 kV and a 161/115 kV XFMR
- I-19: Freeborn to West Owatonna 161 kV new circuit

Of the four solutions, I-2 had the highest benefit-to-cost ratio, largest 20-year PV benefit, and fully relieved the congestion on Huntley to Blue Earth 161 kV. I-12, I-15, and I-19 had lower benefit-to-cost ratios, lower 20-year PV benefits, and were unable to fully relieve Huntley to Blue Earth 161 kV. Therefore, I-2 was moved forward for further robustness testing and analysis to help inform the project recommendation decision for I-2.

Contingency analyses were performed to identify additional flowgates to monitor what could be impacted as a result of Huntley to Wilmarth 345 kV going into service. Some of these additional flowgates did bind due to I-2, and therefore, a refinement of the solution was considered to see if any additions or modifications to the project would be appropriate. Thus, two additional options were considered: I-2b, which consisted of Huntley to Wilmarth 345 kV and an upgrade on Wilmarth to Swan Lake to Ft Ridgley 115 kV; and I-2d, which is the same as I-2b plus a second Helena to Scott 345 kV circuit and an upgrade on Scott Co to Scott Co Tap 115 kV. Reliability analysis on all three of these options - I-2, I-2b and I-2d - revealed that none of these solutions caused additional voltage or thermal violations.

Also, various sensitivity analyses were performed to help inform the project's business case under different potential scenarios. These sensitivity tests evaluated the impact of future Sherco units' retirements, the removal of external RRF wind from Iowa and Minnesota, and modeling wind units in the queue with DPP or GIA-in-Progress status instead of RGOS/RRF wind units in Iowa and Minnesota. Under all of these sensitivities, Huntley to Wilmarth 345 kV was shown to be robust and maintain a benefit-to-cost ratio over 1.25. The results of the queue wind sensitivity in particular compared with the results of the base MTEP16 model can be seen in Table 5.3-1.

ID	Transmission Solution	Model	Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
				BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	Base	88-108	0.43-0.52	1.16-1.42	0.10-0.13	1.32-1.62	3.63-4.45	1.51-1.86	210
		Queue Wind Sensitivity		1.39-1.71	2.40-2.95	0.69-0.85	2.45-3.01	2.03-2.49	1.86-2.28	251
I-2b	Huntley – Wilmarth 345 kV new circuit, Wilmarth to Swan Lake – Ft Ridgeley 115 kV upgrade	Base	113.3-133.3	0.37-0.43	1.12-1.31	0.09-0.10	1.15-1.35	3.31-3.90	1.36-1.60	234
		Queue Wind Sensitivity		1.13-1.33	2.08-2.45	0.55-0.65	2.02-2.39	1.73-2.03	1.55-1.83	259
I-2d	Huntley – Wilmarth 345 kV new circuit, Wilmarth – Swan Lake – Ft Ridgeley 115 kV upgrade Add 2nd Helena – Scott County 345 kV circuit, Scott Co – Scott Co Tap 115 kV upgrade	Base	154.8-174.8	0.27-0.31	0.92-1.04	0.08-0.10	0.98-1.11	3.03-3.43	1.21-1.36	272
		Queue Wind Sensitivity		0.86-0.97	1.74-1.97	0.44-0.50	1.68-1.90	1.55-1.76	1.30-1.47	285

Table 5.3-1: Huntley to Wilmarth 345 kV options sensitivity analysis results

Further investigating the incremental benefits among the three project alternatives in Table 5.3-1, MISO found that the additional upgrades included as part of I-2b and I-2d would not be economically justifiable, as the benefit yielded by these upgrades would not outweigh their incremental cost.

MISO also evaluated the robustness of Huntley to Wilmarth 345 kV under varying levels of future wind additions. The Queue Wind Sensitivity, which was performed in May 2016, utilized the capacity and locations of the queue wind units in Iowa/Minnesota with a DPP or GIA-in-Progress status at that time. The capacity of queue wind units with a SPA status was not included in this analysis.

Based on the analysis results and stakeholder feedback, MISO recommends the Huntley to Wilmarth 345 kV project to MISO Board of Directors for approval as a Market Efficiency Project (MEP) in MTEP16.

Illinois

Two top flowgates are identified in this region (Figure 5.3-9). A large amount of economical nuclear, coal and wind generation is sited in northern Illinois (mainly PJM COMED resources) and tends to serve nearby MISO and PJM loads. The Fargo to Oak Grove 345 kV line is a high-voltage flow path located in this area and allows COMED generation to serve load centers in the Minneapolis/St. Paul, Davenport and Chicago. The flow transfer on this line also increases flow on lines nearby, leading to congestion on Quad Cities to Rock Creek 345 kV. The congestion on Quad Cities to Rock Creek 345 kV also increases significantly when large amounts of future PJM wind generation are sited in northern Illinois in out-year models, particularly in the 10- and 15-year-out models.

Additionally, there is a generation pocket in southern Illinois that contains more than 1,000 MW of coal generation that is limited by transmission outlet capacity. The generation located within this pocket is transferred out through the West Mt Vernon to East West Frankfort 345 kV line or the underlying 138 kV transmission path. Under loss of this 345 kV line, flows shift to the lower voltage system causing heavy congestion.

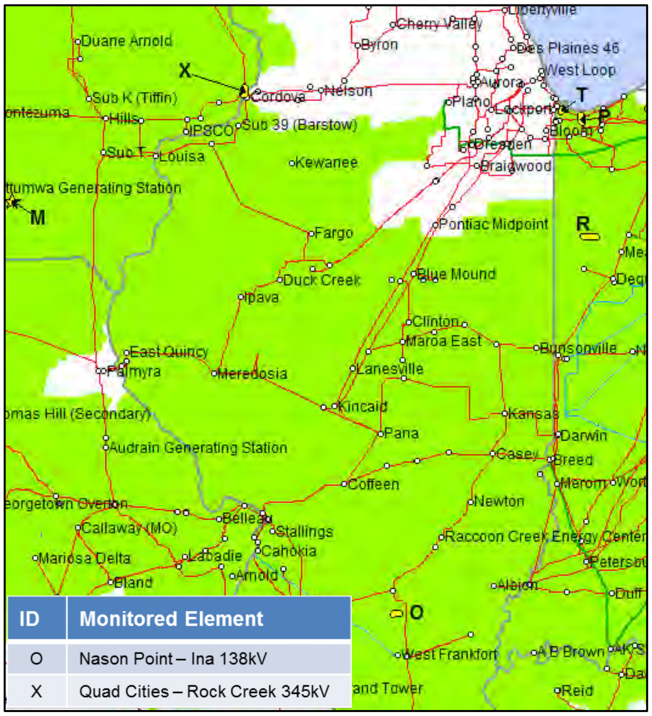


Figure 5.3-9: Illinois Top Congested Flowgates

Of the nine solutions studied in the Illinois area, two passed the initial screening analysis:

- Quad Cities to Rock Creek 345 kV Reconductor
- Quad Cities to Rock Creek 345 kV Second Circuit

Both solutions were designed to address the congestion seen on the Quad Cities to Rock Creek 345 kV line. However, it was determined that the congestion on this constraint was largely driven by the assumed additions of future wind generation in COMED, which was present in MISO's MTEP model but not PJM's RTEP model, a result of a difference in planning assumptions between MISO and PJM. As a result of these findings along with stakeholder feedback, these two solutions were not further evaluated as part of the MTEP16 MCPS.

In southern Illinois, none of the solutions to address congestion on Nason Point to Ina 138 kV line passed the screening, since a terminal equipment upgrade at the Ina substation (targeting for Appendix A in MTEP17) can relieve about 90 percent of the congestion.

Northern Indiana

Congestion is identified in northern Indiana on four different flowgates (Figure 5.3-10). The congestion in this area is primarily driven by the high levels of west-to-east flows across the high voltage lines. This leads to heavy congestion on the lower-voltage system under the outage of these high-voltage lines. In addition, congestion in this area is driven by the flows associated with serving the industrial and non-industrial load pockets along the southern border of Lake Michigan. This is exacerbated by the retirements of Bailly units 7 and 8 in the out-year models, thus increasing the need to transport power to various load centers along the southern border of Lake Michigan. These congestion drivers mainly apply to Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV and Roxana to Praxair 138 kV.

The remaining constraint, Goodland to Remington 69 kV, is primarily congested due to the significant amount of wind located near the border of Illinois and Indiana.

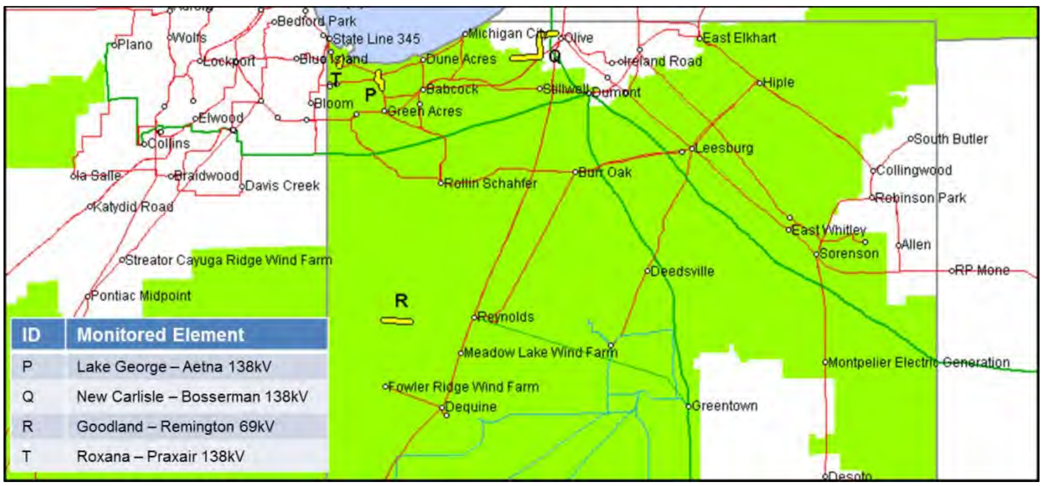


Figure 5.3-10: North Indiana Top Congested Flowgates

The assumed retirement of Bailly 7 and 8 had a large impact in this area by increasing congestion levels on the top flowgates identified in out-year simulations. However, MISO further investigated this congestion and found a standing operating guide that states whenever Bailly 7 and 8 are out of service, the Dune Acres transformer can be restored to service. Because some years/futures assume the retirement of Bailly 7 and 8, the Dune Acres transformer should be modeled as in-service for those respective years and futures. By closing this transformer, congestion on these constraints decreases substantially. Specifically, the congestion on Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV and Roxana to Praxair 138 kV decreases between 33 percent and 90 percent.

Since screening is performed utilizing only 2030, it was decided that for the purposes of the screening the Dune Acres transformer would be modeled as out of service so as to not prematurely exclude any solutions that could end up performing well when considering all years. Therefore, of the 25 solutions submitted for evaluation in this area, six passed the screening analysis.

As part of the PV analysis, the Dune Acres transformer was modeled to reflect the impact of the operating guideline details for each year and future (Table 5.3-2).

	BAU/HD/LD Assumptions			RCPP/SRCPP Assumptions		
	Baily 7	Baily 8	Dune Acres XFMR	Baily 7	Baily 8	Dune Acres XFMR
2020	Online	Online	Open	Online	Online	Open
2025	Retired	Online	Open	Retired	Retired	Closed
2030	Retired	Retired	Closed	Retired	Retired	Closed

Table 5.3-2: Dune Acres Transformer Modeling Assumptions for PV Analysis

As a result, the benefits of the five solutions targeting Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV, or Roxana to Praxair 138 kV reduced and the solutions were not considered as project candidates (Table 5.3-2). The lone solution targeting Goodland to Remington 69 kV that passed screening had a relatively higher benefit-to-cost ratio but was also too low to be considered as a project candidate. Based on the results, no project candidates were identified in Northern Indiana for further analysis.

ID	Transmission Solution	Cost Estimate (2016 $M)	Benefit to Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-20	SE Gary – Aetna 345 kV, tap Gary Ave – Dune Acres 345 kV and Lake George – Munster 345 kV lines into SE Gary*	48.3	0.09	0.17	0.08	0.19	0.36	0.19	12.90
I-26	New Sub* – Aetna 345 kV, Aetna 345/138 kV XFMR, tap Dune Acres – Gary 345 kV into New Sub*	27.3	0.01	-0.01	0.13	0.31	0.27	0.18	6.48
I-35	Thayer – Morrison 138 kV	35	0.56	0.63	0.25	1.05	1.44	0.89	42.02
I-40	Tap Gary – Dune Acres 345 kV into Burns Ditch South	17	0.38	0.11	0.27	0.51	0.56	0.42	9.27
I-50	New Carlisle – Liquid Carbonics 138 kV and Northern Indiana Upgrades	25.2	0.11	0.00	0.06	0.37	1.13	0.42	15.42
I-58	Lake George – Aetna 345 kV, Aetna 345/138 kV XFMR	36.7	0.11	0.00	0.14	0.24	0.21	0.17	7.97

Table 5.3-3: North Indiana PV Analysis Results

Amite South/DSG

A significant amount of congestion was identified in the Amite South and DSG load pockets, particularly on the import lines into the load pockets (Figure 5.3-11). In the event that an import line into either the Amite South or DSG load pocket is outaged (N-1) along with the loss of a generator (G-1) inside the load pocket, flows shift to the remaining import lines. This causes heavy congestion as well as Voltage and Local Reliability (VLR) commitments in the Amite South and DSG load pockets. Further aggravating the congestion are the import limitations of the transmission system as well as the limited economic generation resources available inside the Amite South and DSG load pockets. Construction of additional import lines into Amite South or DSG would therefore help to alleviate congestion as well as VLR issues in this area and can provide easy access to economic generation in these load pockets.

Figure 5.3-11: Amite South/DSG Top Congested Flowgates

Through collaboration with stakeholders, MISO evaluated different generation scenarios as part of the robustness testing for projects identified in the Amite South and DSG load pockets (Table 5.3-4).

Scenario	Name	Siting Location	In-Service Year by Future				
			BAU	HD	LD	RCPP	SRCPP
1	RRF MISO CC:20	Little Gypsy 230 kV		2021		2020	2020
	RRF MISO CT:47	Michoud 230 kV		2029			
2	RRF MISO CC:20	White Bluff 500 kV		2021		2020	2020
	RRF MISO CT:47	Big Cajun 500 kV		2029			
3	Scen3 MISO CC:1	Little Gypsy 230 kV	2020	2020	2020	2020	2020
	Scen3 MISO CT:1	Michoud 230 kV		2029			

Table 5.3-4: Amite South/DSG Generation Scenarios

In Table 5.3-4 Generation Scenario 1 refers to the base Regional Resource Forecast (RRF) siting agreed upon by stakeholders as part of the model development for MTEP16. Scenario 2 was developed to reflect the potential future condition of all future RRF units being sited outside of the MISO South load pockets, while Scenario 3 was proposed by stakeholders to capture the potential impacts of Entergy's Request for Proposal (RFP) generation. In order to better quantify the potential impacts of Scenario 3, network upgrades identified during the Generation Interconnection J396 study were included as a base case assumption. One important difference between the scenarios is the size of the future units added to the model. In Scenario 1 and Scenario 2 the RRF units are sized at 600 MW, while in Scenario 3 the Combined Cycle (CC) units are sized at 900 MW and the Combustion Turbine (CT) units are sized at 250 MW.

Twenty-two projects were submitted to address congestion in Amite South and DSG load pockets. These projects aimed to address issues of increased transfer capabilities into the Amite South and DSG load pockets, as well as alleviating congestion within the load pockets. After the completion of screening and refinement, three projects were identified as potential solutions to address congestion within the Amite South and DSG load pockets (Table 5.3-5 and Table 5.3-6).

Transmission Solution	Project Description
Amite South/DSG Alternative 2	• Reconductor existing facilities: ➢ Snakefarm to Labarre 230 kV ➢ Prospect to Goodhope 230 kV • Rebuild Existing facilities: ➢ Panama - Wilton to Romeville to Convent 230 kV ➢ St. Gabriel to AAC Corp to Licar 230 kV ➢ Evergreen to Donaldsonville to Bayou Verret 230 kV • Re-energize Little Gypsy to Luling 115 kV to 230 kV and tap into Waterford • Add two new Waterford 500/230 kV XFMRs
DSG Alternative 2	• Reconductor existing facilities: ➢ Snakefarm to Labarre 230 kV ➢ Prospect to Goodhope 230 kV • Re-energize Little Gypsy to Luling 115 kV to 230 kV and tap into Waterford
DSG Alternative 6	• Construction of new 230 kV substation called Churchill (new substation to south of Nine Mile) • Construction a new Waterford to Churchill 230 kV line • Re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation

Table 5.3-5: Amite South/DSG project alternative descriptions

Transmission Solution	Cost ($M)	ISD*	Weighted Benefit-to-Cost Ratios			Weighted Benefits (2016 $M)		
			Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Amite South/DSG Alternative 2	134.1	2020	2.34	2.20	1.35	443	417	256
DSG Alternative 2	22.0	2020	12.08	8.62	7.27	376	269	226
DSG Alternative 6	87.7	2022	3.42	2.08	1.96	390	238	223

***In Service Date**

Table 5.3-6: Amite South/DSG project PV analysis results

In addition these three project alternatives were subject to additional robustness analysis to quantify the impacts of the 55-year age-related retirement assumption of the MTEP17 futures applied to Nine Mile: 4 and Nine Mile: 5 in the DSG load pocket. This sensitivity analysis was performed both with and without generation replacement at the Nine Mile substation; a 900 MW CCGT was used as a replacement sensitivity and assumed to be sited at Nine Mile.

In comparing Amite South/DSG Alternative 2 to DSG Alternative 2, the robustness analysis showed minimal incremental benefits for rebuilding Amite South in Scenario 3. However, in the case that Nine Mile:4 and Nine Mile:5 are retired and not replaced by new CCGT generation, DSG Alternative 6 potentially provides significantly more benefits in Scenario 3 compared to DSG Alternative 2 (Table 5.3-7).

Transmission Solution	Case	Weighted Benefit-to-Cost Ratios			Weighted Benefits (2016 $M)		
		Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Amite South/DSG Alternative 2	Base Case	2.34	2.20	1.35	443	417	256
	Retire Nine Mile	12.16	12.04	5.71	2,280	2,262	1,075
	Replace Nine Mile	3.56	4.92	1.30	670	930	247
DSG Alternative 2	Base Case	12.08	8.62	7.27	376	269	226
	Retire Nine Mile	69.58	56.97	33.47	2,142	1,755	1,034
	Replace Nine Mile	20.46	26.27	7.42	631	815	230
DSG Alternative 6	Base Case	3.42	2.08	1.96	390	238	223
	Retire Nine Mile	22.14	16.75	13.35	2,481	1,877	1,501
	Replace Nine Mile	5.84	6.89	2.20	656	781	249

Table 5.3-7: Amite South/DSG project alternatives robustness analysis

Additionally, a reliability analysis was performed to determine the import capability of the competing alternatives into the Down Stream of Gypsy (DSG) load pocket. In comparing all three alternatives, DSG Alternative 6 increases the import capability into the DSG load pocket by 650 MW (Table 5.3-8).

Transmission Solution	DSG Load Pocket Import Capability (MW)	Maximum Load Serving Capability (MW)	Constraining Element
Base Case	1,645	3,618	Prospect to Good Hope 230 kV FTLO Waterford to Ninemile 230 kV
Amite South/DSG Alternative 2	1,520	3,375	Little Gypsy to Claytonia 115 kV FTLO Little Gypsy – Wesco 230 kV
DSG Alternative 2	1,520	3,375	Little Gypsy to Claytonia 115 kV FTLO Little Gypsy – Wesco 230 kV
DSG Alternative 6	2,295	3918	Prospect to Good Hope 230 kV FTLO Waterford to Ninemile 230 kV

Table 5.3-8: Amite South/DSG project alternative import and load serving capability

DG Alternative 6, located in Southeast Louisiana, is to construct a new 230 kV substation south of the existing Ninemile substation called Churchill and construct a new 230 kV transmission line connecting the existing Waterford 230 kV substation to Churchill 230 kV substation. Additionally, re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation. This economic Other Project provides additional benefits to Amite South and Down Stream of Gypsy (DSG) load pockets. This project provides an outlet and improves the import capability by 650 MW into the DSG load pocket. Also, it provides operational flexibility in the region during planned transmission outages as well as accommodating the system for any future retirements. MISO recommends this project to the Board of Directors as an economic Other Project for approval in MTEP16.

WOTAB/Western

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

The 2016 MCPS study for the South region identified that the majority of the congestion in this focus area is on import lines into the WOTAB load pocket (Figure 5.3-12). In the event that one of the import lines, most notably the 500 kV lines, into the WOTAB load pocket is outaged and a generator is lost inside of the WOTAB load, pocket flows shift to the remaining import lines.

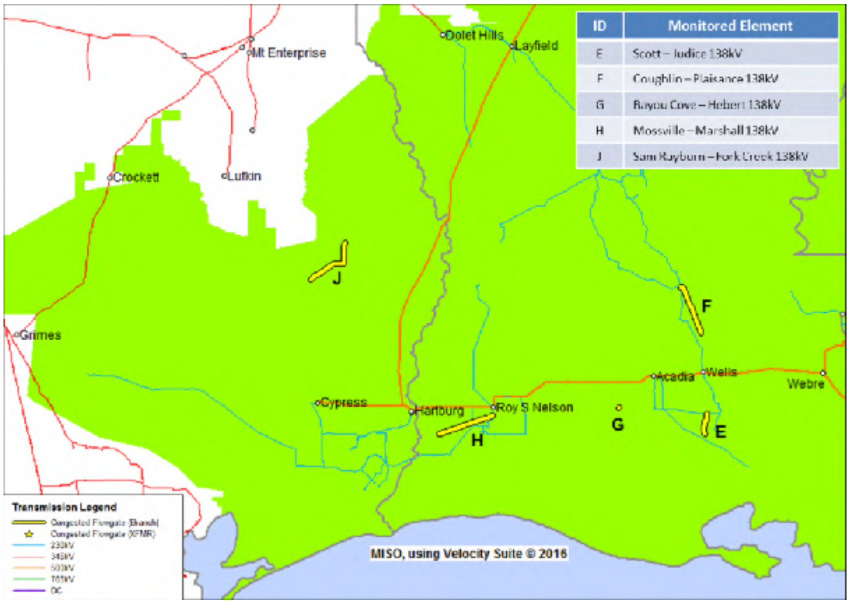


Figure 5.3-12: WOTAB/Western Top Congested Flowgates

Eighteen projects were submitted to address congestion in the WOTAB and Western load pockets. These projects were designed to provide increased transfer capabilities into the WOTAB and Western load pockets, as well as alleviating internal congestion within the load pockets. After the completion of screening, none of the submitted projects produced adequate benefits to pass the screening criteria.

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

Remainder of LRZ9 (Rest of Louisiana)

The identified congestion in the Remainder of LRZ9 (Rest of Louisiana) spreads across the footprint with the majority of congestion on the Minden to Sarepta 115 kV line in northwest Louisiana, and on the Red Gum to Natchez 115 kV line on the border of Louisiana and Mississippi (Figure 5.3-13).

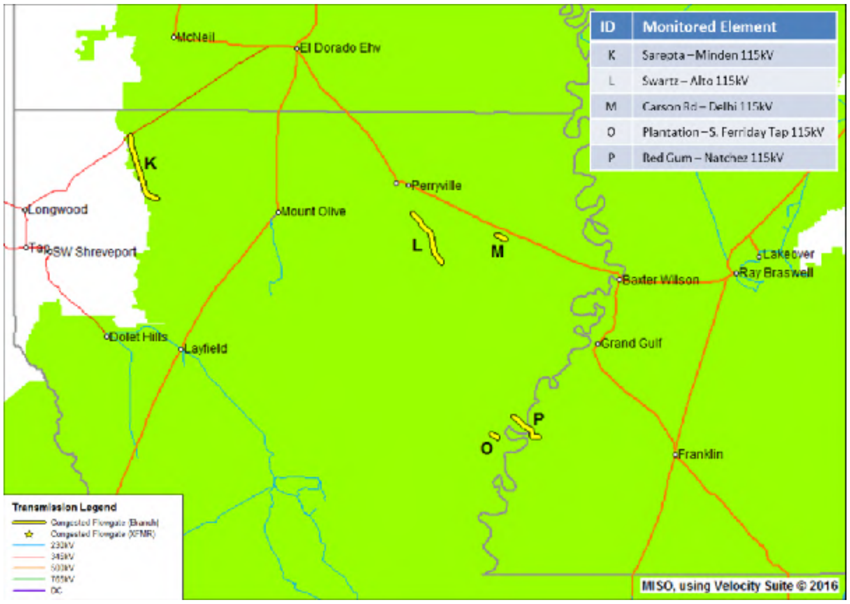


Figure 5.3-13: Remainder of LRZ9 (Rest of Louisiana) Top Congested Flowgates

A total of 17 projects were submitted to address the congestion in the Remainder of LRZ9 (Rest of Louisiana). After the completion of screening and refinement, two projects were selected for further evaluation.

One of the two projects, New Murray Tap to S. Natchez 115 kV, mitigated the congestion seen on the Red Gum to Natchez 115 kV and Plantation to S. Feriday Tap 115 kV lines. The robustness analysis determined that benefits of the project are reduced by re-siting the MISO PV Solar (RRF) in the RCPP and SRCPP futures. This sensitivity analysis leads to a reduction in the congestion seen on the Red Gum to Natchez 115 kV constraint, thus reducing the weighted benefit-to-cost ratio below the 1.25 threshold. This congestion will continue to be studied as part of future planning cycles.

The remaining project selected for further evaluation in this area upgrades the terminal equipment on the existing Minden to Sarepta 115 kV line. This project is identified as the best-fit solution to mitigate the congestion observed on this constraint and produces benefits that exceed the costs (Table 5.3-9).

MISO recommends the upgrade of the Minden to Sarepta 115 kV terminal equipment to the board as an economic Other Project in MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit to Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Upgrade Minden to Sarepta 115 kV Terminal Equipment	$1.9	2020	(0.29)	2.59	0.57	0.88	5.06	**1.83**

***In Service Date**

Table 5.3-9: Upgrade Minden to Sarepta 115 kV terminal equipment PV analysis results

LRZ10 (Mississippi)

The majority of the identified congestion in LRZ10 is localized on the Lakeover 500/115 kV autotransformer for the loss of the Lakeover to Ray Braswell 500 kV line (Figure 5.3-14).

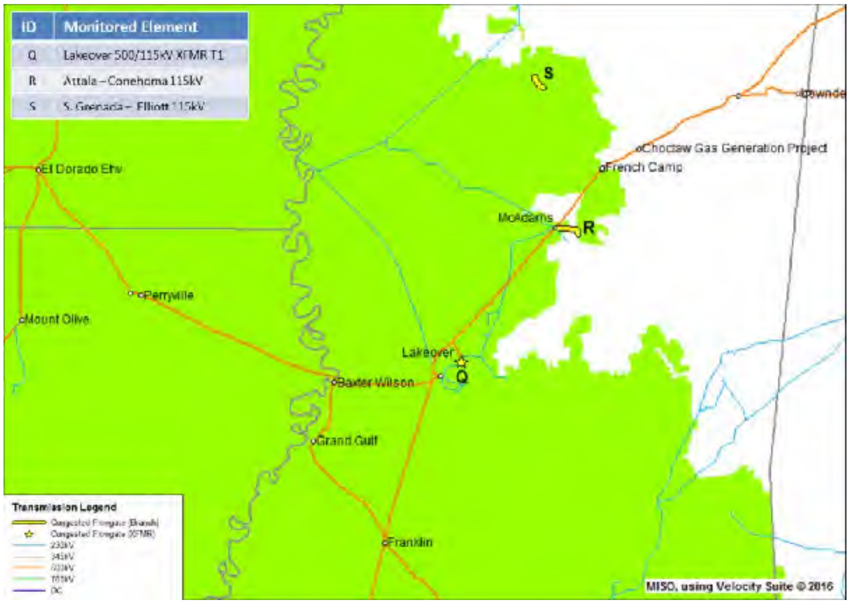


Figure 5.3-14: LRZ10 (Mississippi) Top Congested Flowgates

A total of 10 projects were submitted to address the congestion in LRZ10. After the completion of screening and refinement it became apparent that an adequate benefit-to-cost ratio is dependent on the ability to relocate the existing 500/230 kV autotransformer at McAdams to the Lakeover substation (Table 5.3-10).

MISO recommends the relocation of the existing 500/230 kV autotransformer at McAdams to the Lakeover substation to the Board as an economic Other Project in MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit-to-Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Lakeover 500/230 kV XFMR	$6.7	2020	2.63	1.80	0.93	2.05	(0.06)	**1.43**

***In Service Date**

Table 5.3-10: Lakeover 500/230 kV XFMR PV analysis results

LRZ8 (Arkansas)

The identified congestion in LRZ8 was spread across the footprint with the majority of congestion showing on the Morrilton East to Gleason 161 kV line in central Arkansas, and on the Trumann to Trumann West 161 kV line in northeast Arkansas (Figure 5.3-15).

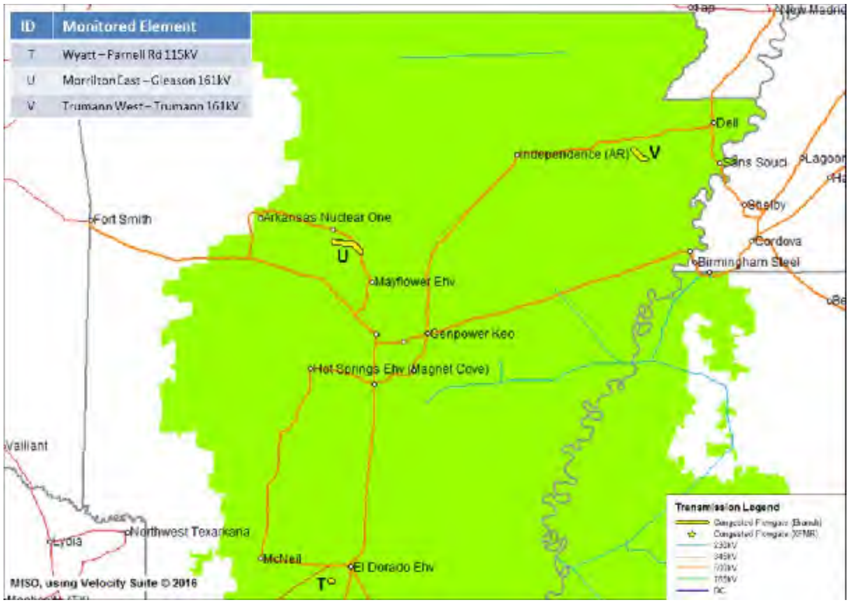


Figure 5.3-15: LRZ8 (Arkansas) Top Congested Flowgates

A total of 10 projects were submitted to address the congestion in LRZ8. After the completion of screening and refinement, two projects were selected for further evaluation.

One of the two projects, Rebuild Morrilton East to Tyler 161 kV, mitigated the congestion seen on the Morrilton East to Gleason 161 kV line. The robustness analysis determined that the benefits of the project are significantly impacted by the SERC wind that is sited in SPP footprint. A sensitivity study was performed, which deactivated this SERC wind in order to quantify the impact to the weighted benefit-to-cost ratio. This sensitivity resulted in the weighted benefit-to-cost ratio dropping significantly below the 1.25 threshold. This congestion will continue to be studied as part of future planning cycles.

The remaining project selected for further evaluation in this area rebuilds the existing Trumann to Trumann West 161 kV line. This project is identified as the best-fit solution to mitigate the congestion observed on the Trumann to Trumann West 161 kV line and produces benefits that well exceed the costs (Table 5.3-11).

The rebuild of Trumann to Trumann West 161 kV is recommended to the Board as part of MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit to Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Rebuild Trumann to Trumann West 161 kV	$7.6	2018	12.69	3.06	19.72	15.29	11.60	**13.36**

***In Service Date**

Table 5.3-11: Rebuild Trumann to Trumann West 161 kV PV analysis results

Book 2
Resource Adequacy

2016

Chapter 6
Resource Adequacy

2016

6.0 Resource Adequacy Introduction and Enhancements

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

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

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

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

- Informed by stakeholder feedback, MISO is developing a capacity market construct (referred to as the "Competitive Retail Solution") for retail choice areas to assure Resource Adequacy while preserving the existing construct for the remainder of the footprint
- Interconnection Queue Reform
- Seasonal Reliability and Locational proposals including:
    - Visibility into winter resource adequacy risk
    - Ensuring the seasonal variation in resource capability are accounted for
    - Aligning treatment of external and internal resources.

6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM ICAP) for the 2016-2017 planning year, spanning from June 1, 2016, through May 31, 2017, is 15.2 percent, an increase of 0.9 percentage point from the 14.3 percent PRM set in the 2015-2016 planning year (Figure 6.1-1).

The PRM ICAP is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 0.9 percentage point PRM ICAP increase was the net effect of several modeling parameters such as changes to load forecast, load forecast uncertainty and resource characteristics.

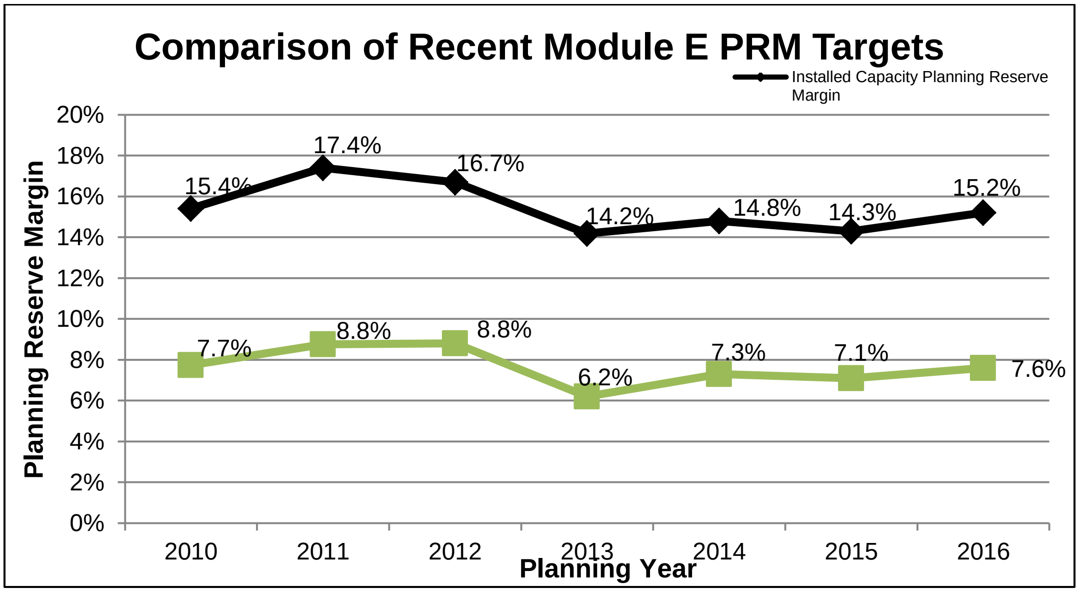


Figure 6.1-1: Comparison of recent PRM

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

The LOLE study and the deliverables from the Loss of Load Expectation Working Group (LOLEWG) are based on the Resource Adequacy construct per Module E-1. MISO performs an LOLE study to determine the congestion-free PRM on an installed and unforced capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined for each Local Resource Zone (LRZ) (Figure 6.1-2), which is defined as the amount of resources a particular area needs to meet the LOLE criteria of one day in 10 years without the benefit of the Capacity Import Limit (CIL).

These results are merged with the CIL, Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.

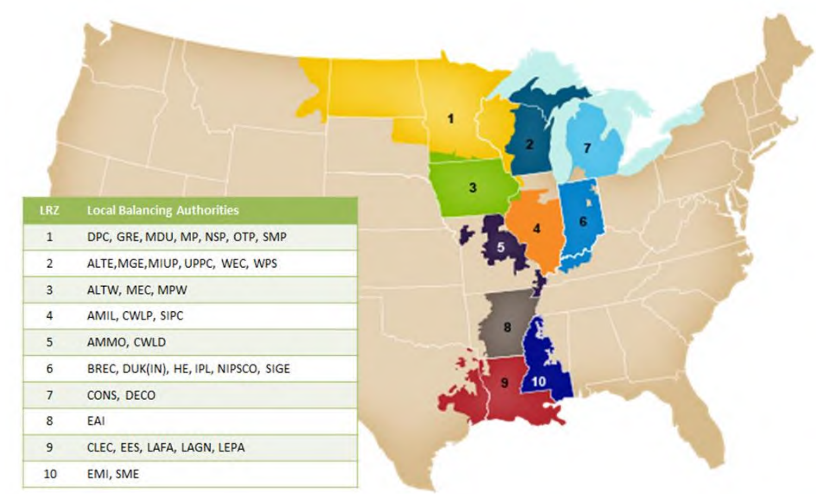


Figure 6.1-2: Local Resource Zones (LRZ)

2016-2017 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM UCAP, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1). The PRM UCAP increased from 7.1 percent to 7.6 percent due to the modeling parameter changes. More information on the increase is available in the 2016 LOLE report. Under the existing construct, the PRM UCAP is applied to the peak of each Load Serving Entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). Adjustments were made to CIL based on FERC order on accommodation of resources committed to non-MISO load. The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the resources cleared in the auction can be reliably delivered.

RA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
LRR UCAP per-unit of LRZ Peak Demand	1.110	1.143	1.129	1.218	1.210	1.108	1.132	1.257	1.125	1.392
Capacity Import Limit (CIL) (MW)	3,436	1,609	1,186	6,323	4,837	5,610	3,521	3,527	4,490	2,653
Capacity Export Limit (CEL) (MW)	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857

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

LRZ	Tier	16-17 Limit (MW)[39]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	Initial Limit (MW)[40]	Generation Redispatch Details		15-16 Limit (MW)
							MW	Area(s)	
1	1 & 2	3,436	Colby to Northern Iowa Windpower 161 kV Line	Adams to Barton 161 kV Line	1	3,432	N/A	N/A	3,735
2	1	1,609	Stoneman to Nelson-Dewey 161 kV Line	Wempletown to Paddock 345 kV Line	2	1,111	188	METC, XEL, MP, DPC	2,903
3	1	1,186	Palmyra 345-161 kV Transformer	Palmyra Tap to Sub T 345 kV Line	3	989	2,000	WEC, AMMO, AMIL, GRE, MPW	1,972
4	1 & 2	6,323	Palmyra 345/161 kV Transformer	Montgomery to Spencer 345 kV Line	3	1,970	2,164	WEC & EES	3,130
5	1	4,837	Russellville East to Russellville South 161 kV Line	Arkansas Nuclear One to Fort Smith 500 kV Line	4	4,297	491	AMIL, ALTW, OTP, MEC	3,899
6	1 & 2	5,610	Rising 345/138 kV Transformer	Clinton to Brokaw 345 kV Line	5	3,598	3,020	METC & AMIL	5,649
7	1 & 2	3,521	Argenta to Battle Creek 345 kV Line	Paxton to Tompkins 345 kV Line	6	1,970	2,000	NIPS, CE, WEC	3,813
8	1	3,527	Montgomery to Clarence 230 kV Line	Hartburg to Layfield 500 kV Line	7	0	2,000	AMMO, EES	2,074
9	1	4,490	Andrus 230/115 kV Transformer	Andrus to Indianola 230 kV Line	8	2,579	717	EES & LAGN	*4,008
10	1	2,653	Ray Brasswell Transformer	Ray Brasswell to Lakeover 500 kV Line	9	172	2,000	SMEPA & EES-EMI	*2,630

*Values determined in LRZ Re-evaluation study presented on February 4, 2015, LOLE Working Group

Table 6.1-2: 2016-2017 Planning Year Capacity Import Limits

[39] The 16-17 Limit represents the limit after consideration for redispatch and adjustment for FERC order
[40] The Initial Limit represents the limit before considering redispatch.

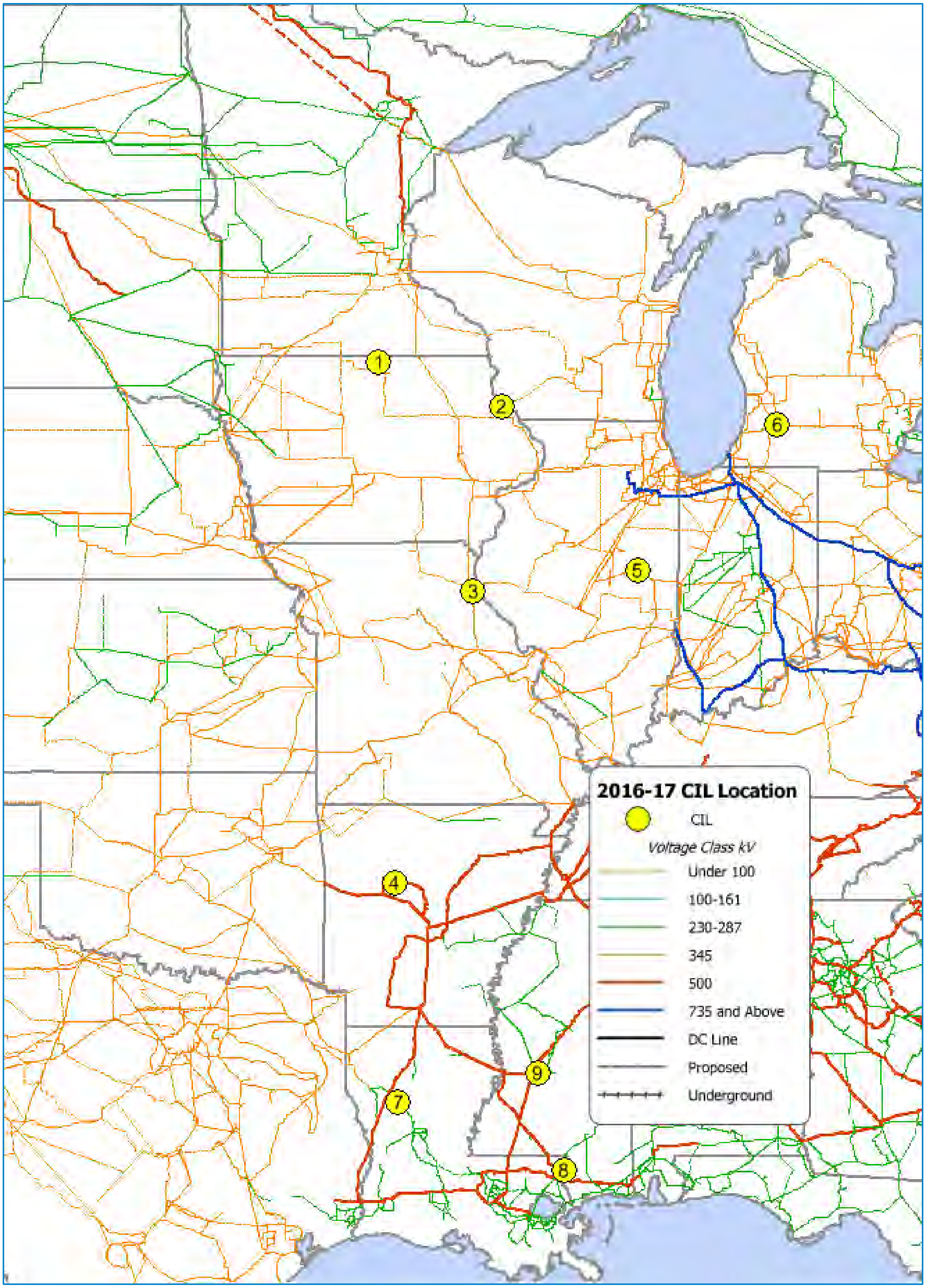


Figure 6.1-3: 2016-2017 Capacity Import Limit map

LRZ	16-17 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	Initial Limit (MW)	Generation Redispatch Details		15-16 Limit (MW)
						MW	Area	
1	590	Lakefield to Dickinson 161 kV Line	Raun to Highland 345 kV Line	1	0	1,627	XEL, MP, GRE, OTP, ALTW, MEC, WPS	604
2	2,996	St Rita To Racine 138 kV Line	Racine to Elm Road 345 kV Line	2	1,259	965	CE	1,516
3	1,598	Oak Grove to Mercer 161 kV Line	Havana Unit 6	3	1,598	0	N/A	1,477
4	7,379	Newton to Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	7,379	0	N/A	4,125
5	896	Newton To Casey 345 kV Line	Casey West to Neoga 345 kV Line	4	0	224	AMMO	0
6	2,544	Tap to AEP Rockport to Grandview 138 kV Line	AB Brown to Reid EHV Substation to Wilson 345 kV Line	5	2,544	0	N/A	2,930
7	4,541	Benton Harbor 345/138 kV Transformer	Benton to Cook 345 kV Line	6	4,541	0	N/A	4,804
8	2,074	Russelville North to Russelville East 161 kV Line	Arkansas Nuclear One to Fort Smith 500 kV Line	7	2,074	0	N/A	3,022
9	1,261	Port Neches Bulk to Flatland 138 kV Line	Sabine 345/138 kV Transformer	8	0	2,000	EES, LAFA, LEPA, CLECO	*2,418
10	1,857	Plant Morrow to Purvis Bulk 161 kV Line	Plant Morrow to Purvis Bulk 161 kV Line	9	0	2,000	EES-EMI, SMEPA	*1,959

*Values determined in LRZ Re-evaluation study presented on February 4, 2015, LOLE Working Group

Table 6.1-3: 2016-2017 Planning Year Capacity Export Limits

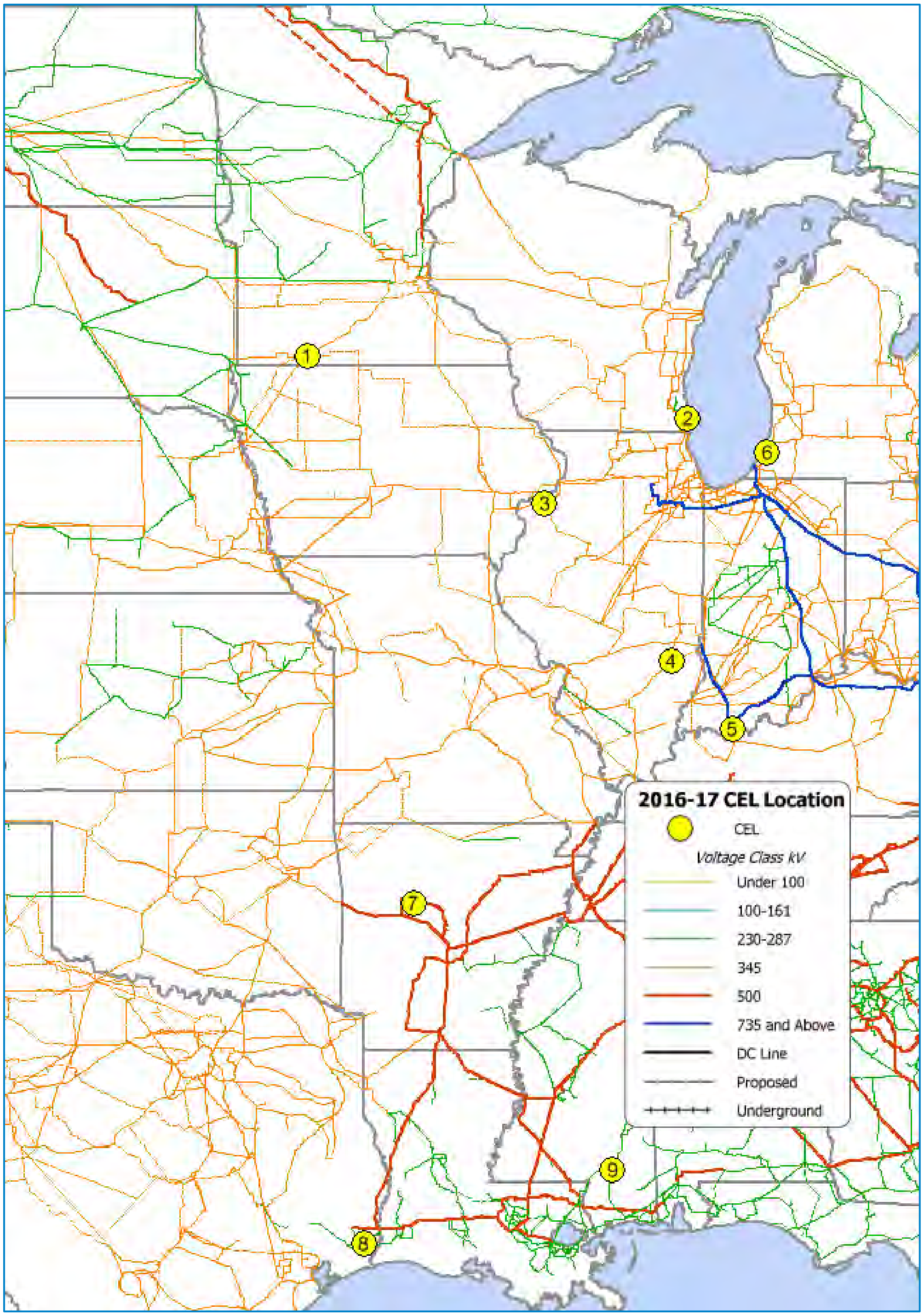


Figure 6.1-4: 2016-2017 Capacity Export Limit map

MTEP Projects and Capacity Import and Export Limits

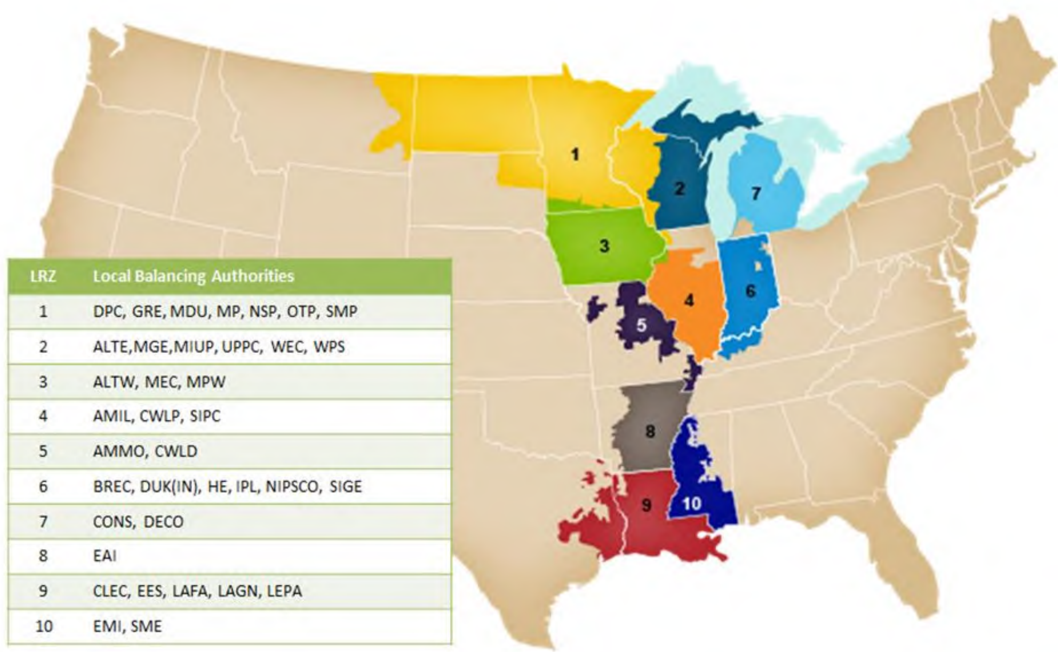
The Capacity Import and Export Limits are deliverables to the PRM for the Planning Resource Auction and are considered in the development of the MTEP. Table 6.1-4 is a list of projects potentially impacting the most limiting elements observed in the CIL and CEL results as shown in Tables 6.1-2 and 6.1-3.

Year	LRZ	CEL or CEL	Monitored Element	Contingent Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
16-17	1	CEL	Lakefield to Dickinson 161 kV Line	Raun to Highland 345 kV Line	3205, 3213	A in MTEP14	Proposed MVP Portfolio 1: Lakefield Jct. – Winnebago – Winco – Kossuth County & Obrien County – Kossuth County – Webster 345 kV line and Proposed MVP Portfolio 1 – Winco to Hazleton 345 KV line	9/28/2015 – 6/1/2018, 6/1/2015 – 12/31/2018
16-17	2	CIL	Stoneman to Nelson-Dewey 161 kV Line	Wempletown to Paddock 345 kV Line	3127	A in MTEP11	Proposed MVP Portfolio 1: North LaCrosse – North Madison – Cardinal – Eden – Hickory Creek 345 kV Line	12/31/2017 – 12/31/2023
16-17	2	CEL	St Rita To Racine 138 kV Line	Racine to Elm Road 345 kV Line	3894, 3895	A in MTEP13	Reconductor Racine – Oak Creek 138 kV, Reconductor Oak Creek – Kansas 138 kV	2/22/2016, 6/1/2016
16-17	3, 4	CIL	Palmyra Transformer	Montgomery to Spencer 345 kV	3017	A in MTEP11	Proposed MVP Portfolio 1: Maywood – Herleman – Meredosia – Ipava & Meredosia – Austin 345 kV Line	11/15/2017
16-17	7	CIL	Argenta to Battle Creek 345 kV Line	Paxton to Tompkins 345 kV Line	8067, 4509	A in MTEP15	Beals Road 138 kV Station Equipment Replacement, Argenta – Battle Creek 345 kV Sag Remediation and Station Equipment	6/1/2017, 12/31/2017
16-17	9	CIL	Andrus 230/115 kV Transformer	Andrus to Indianola 230 kV Line	8520	B in MTEP16	Upgrade Andrus 230/115 kV autotransformer. Install 2nd 230/115 kV autotransformer at Indianola.	6/1/2020
16-17	10	CIL	Ray Braswell Transformer	Ray Braswell to Lakeover 500 kV Line	9829	B in MTEP16	Ray Braswell 500/115 upgrade 115 kV breakers	6/1/2019

Table 6.1-4: MTEP projects potentially impacting the most limiting constraints

Wind Capacity Credit

A class-average wind capacity credit of 15.6 percent was established for the 2016-2017 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit increased 0.9 percentage point from the wind capacity credit of 14.7 percent established in the 2015-2016 Planning Year (Figure 6.1-5). For more information, refer to the complete 2016 Wind Capacity Credit Report[41].



LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE,MGE,MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMI, SME

Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	14,732	4,315	627	7,379	644	282	1,486	0	0	0
UCAP (MW)	2,292	813	87	1,042	80	27	244	0	0	0
ELCC %	15.6%	18.8%	13.8%	14.1%	12.4%	9.6%	16.4%	0.0%	0.0%	0.0%
Wind CPnode Count	196	69	10	81	8	4	24	0	0	0

Figure 6.1-5: Wind Capacity Credit by Local Resource Zones (LRZ) for 2016-2017 Planning Year

Solar Capacity Credit

A class-average solar capacity credit of 50 percent was established for the 2016-2017 planning year by estimating the peak period contribution from historical solar irradiance simulation data. New resources without summer operating history will receive this class average capacity credit until at least 30 consecutive days of summer performance data are available, at which time the resource's individual capacity credit will be based on its own operating history. More details can be found in the MISO BPM-011 in section 4.

For more information related to the LOLE study, refer to the Planning Year 2016 LOLE study report.

[41] Or: https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

6.2 Long-Term Resource Assessment

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

MISO forecasts the reserve margin will drop below the PRMR of 15.2 percent beginning in 2018, and will remain below the PRMR for the rest of the assessment period (Table 6.2-1). Falling below the PRMR signifies that the MISO region is projected to operate at a reliability level lower than the one-day-in-10 standard in 2018 and beyond. MISO anticipates the projected margin shortfall will change significantly as Load Serving Entities and state commissions solidify future capacity plans.

This is an expected result, as 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of proper regulatory approvals, such as a Certificate of Public Convenience and Necessity (CPCN). Two years is not sufficient lead time for Load Serving Entities to plan, build and operate new resources to meet the projected shortfall in 2018 and beyond.

In GW (ICAP)	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27
(+) Existing Resources	151.6	151.0	150.7	150.1	149.9	147.8	146.2	145.9	144.9	144.6
(+) New Resources	1.6	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
(+) Imports	4.2	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2
(-) Exports	4.7	4.7	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
(-) Low Certainty Resources	1.8	2.6	3.0	3.0	3.1	3.2	3.2	3.2	3.2	3.2
(-) Transfer Limited	2.9	2.2	1.9	1.8	1.6	1.3	1.0	0.7	0.4	0.1
Available Resources	147.9	147.6	148.7	148.2	148.1	146.3	145.0	144.9	144.3	144.2
Demand	127.6	128.4	129.5	130.2	130.9	131.7	132.3	133.0	133.6	134.5
PRMR	147.0	147.9	149.2	150.0	150.8	151.7	152.4	153.2	153.9	154.9
PRMR Shortfall	0.9	-0.4	-0.5	-1.9	-2.6	-5.4	-7.4	-8.2	-9.6	-10.7
Reserve Margin Percent (%)	15.9%	14.9%	14.8%	13.8%	13.2%	11.1%	9.6%	9.0%	8.0%	7.3%

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

The anticipated PRMR shows a potential regional shortfall against the reserve requirements of 0.4 GW, which is two years earlier than the 2015 MISO LTRA results. The conclusions from the long-term resource assessments are:

- A decrease in resources committed to serving MISO load mainly by independent power producers (IPP)
- A decrease in load forecasts where the biggest drop was in Zone 6 (Indiana)
- The increase in committed resources (Tier 1) in Zone 7 (Michigan)
- MISO projects that each zone within the MISO footprint will have sufficient resources within its boundaries to meet its Local Clearing Requirements, or the amount of its local resource requirement, which must be contained within their boundaries
- Several zones are short against their total zonal reserve requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability and the MISO region has sufficient surplus capacity in other zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.
- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; also MISO is engaged with stakeholders in a number of resource adequacy reforms to help rectify these out-year shortages.

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

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

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

Assumptions

At the end of 2013 MISO and the Organization of MISO States (OMS) conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the third iteration of the OMS-MISO survey in June 2016, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2017, MISO anticipates that the MISO Region's coincident demand will be 127,607 MW, which is a 50/50 weather-normalized load forecast.

In 2017, MISO anticipates that the MISO Region's coincident demand will be 127,607 MW, which is a 50/50 weather-normalized load forecast

Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.6 percent for the period from 2016 to 2026.

Resources

In 2017, MISO expects a total of 147,900 MW of Anticipated Capacity Resources to be available on peak.

In 2017, MISO expects a total of 147,900 MW of Anticipated Capacity Resources to be available on peak

MISO's current registered capacity (nameplate) of 173,289 MW steps down to Existing-Certain Capacity Resources of 141,100 MW by accounting for summer on-peak generator performance (including wind capacity at 15.6 percent of nameplate), transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 141,100 MW towards its PRMR to meet a loss-of-load expectation of one day in 10 years.

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. MISO assumes the 4,144 MW of BTMG dropping to 4,132 in 2021 and 5,827 MW of LMR DR that was qualified in the 2016 Planning Resource Auction to be available throughout the assessment period.

This year, MISO and OMS completed the third iteration of the Resource Adequacy Survey. In the survey, resources that were identified to have a low certainty of serving load were not included (Table 6.2-1).

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 2,665 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period (Figure 6.2-1). This is based on a snapshot of the GIQ as of June 2016 and is the aggregation of active projects with a signed Interconnection Agreement.

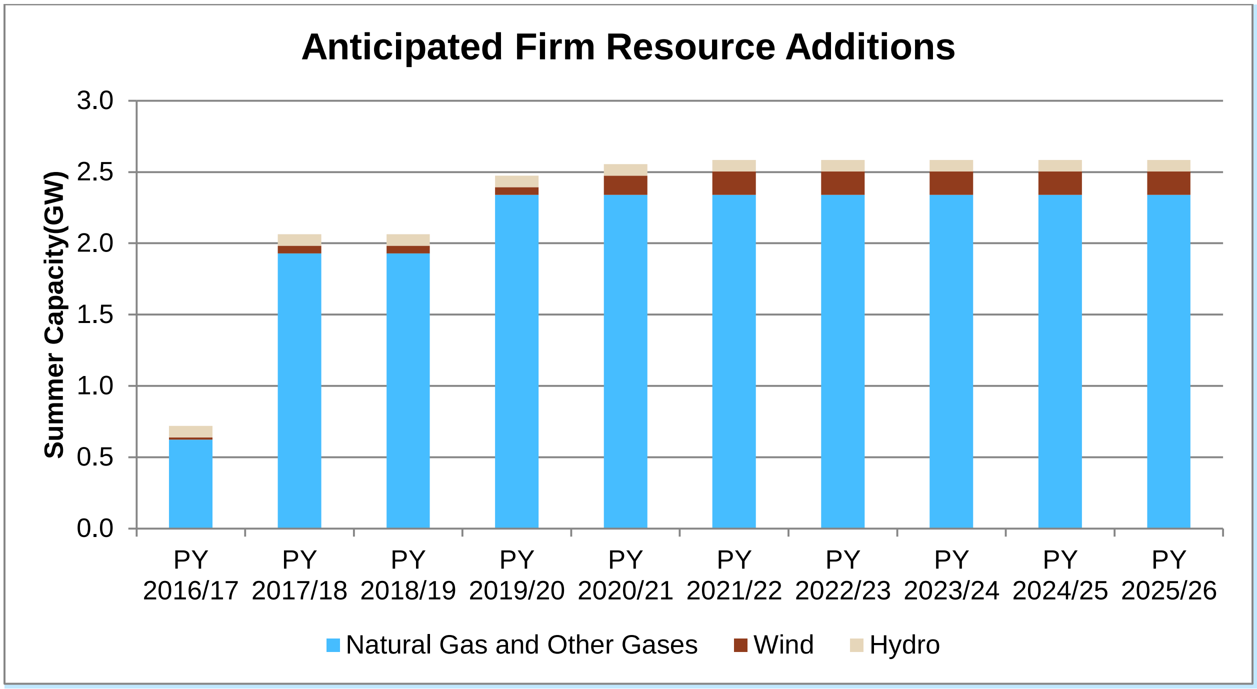


Figure 6.2-1: Anticipated resource additions and uprates (cumulative) in the MISO Region

Imports and Exports

MISO assumes a forecast of 4,213.3 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider. This capacity was designated to serve load within MISO through the Module E process for summer 2016. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 4,744.7 MW of firm capacity exports in year 2017. Exports are projected to decrease to 3,900 MW in 2019 and remain at that level for the rest of the assessment period.

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

6.3 Seasonal Resource Assessment

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

The 2015-2016 winter and 2016 summer season findings show that the projected capacity levels exceed the Planning Reserve Margin Requirement, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with intra-Regional Transmission Owner (RTO) expected dispatch, only 876 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios for the 2016 Summer Assessment.

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

Demand

Based on 21 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2016 LOLE Study.

Demand Reporting

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

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

2015-2016 Winter Overview

For planning year 2015-2016, MISO's Planning Reserve Margin Requirement (PRMR) was 14.3 percent. For the 2015-2016 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 41.0 percent, which far exceeds the PRMR of 14.3 percent. The winter scenarios project the reserve margin to be in the range of 34.1 to 43.6 percent (Figure 6.3-1).

MISO's 50/50 coincident peak demand for the 2015-2016 winter season was forecasted to be 103,965 MW including transmission losses, with 146,613 MW of capacity to serve MISO load during the 2015-2016 winter season. Excluded from the capacity are 3,955 MW of MISO South resources to align with the Planning Resource Auction (PRA) Sub-Regional Export Constraint (SREC).

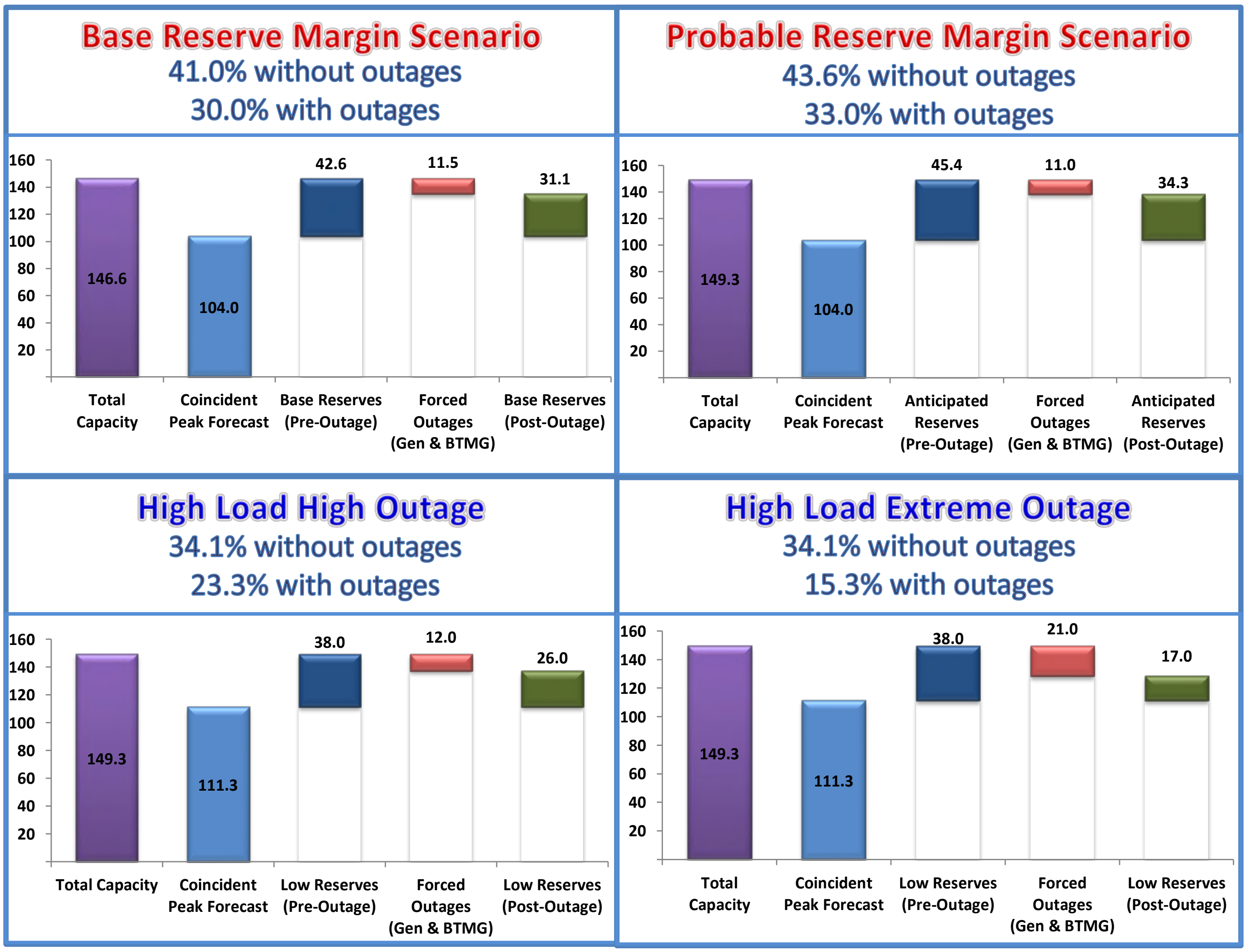


Figure 6.3-1: Winter 2015-2016 Projected Reserve Margin scenarios (GW)

2015-2016 Winter Rated Capacity

For the 2015-2016 winter season, MISO projected 146,613 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 2,699 MW of Behind-the-Meter Generation (BTMG) and 4,047 MW of Demand Resource (DR) programs, with 56 MW of Net Firm Exports. MISO expected 1,388 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 6,009 MW; thermal unit winter output reductions of 7,307 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 10,321 MW based on available nameplate wind resources of 12,161 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 1,000 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

For more information regarding methodology and assumptions of the Winter Rated Capacity, refer to Appendix A.2 of the 2015-2016 Winter Resource Assessment.

Winter Reserve Margin Scenarios

MISO's projected 2015-2016 MISO Winter Rated Capacity varies by scenario (Figures 6.3-2 through 6.3-6). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 111,313 MW for the 2015-2016 winter. For more information regarding each scenario, refer to Appendix A.3 of the 2015-2016 Winter Resource Assessment.

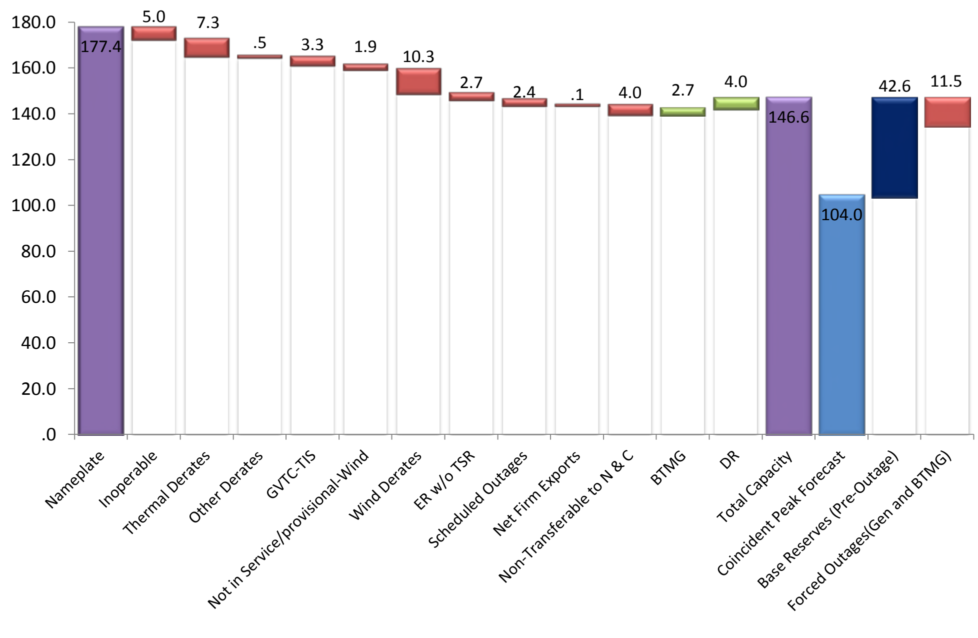


Figure 6.3-2: 2015-2016 Winter Rated Capacity projected Base scenario (GW)

The anticipated scenario contains additional assumptions (Figure 6.3-3). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 1,000 MW contract path limitation for the 2015-16 Planning Year.

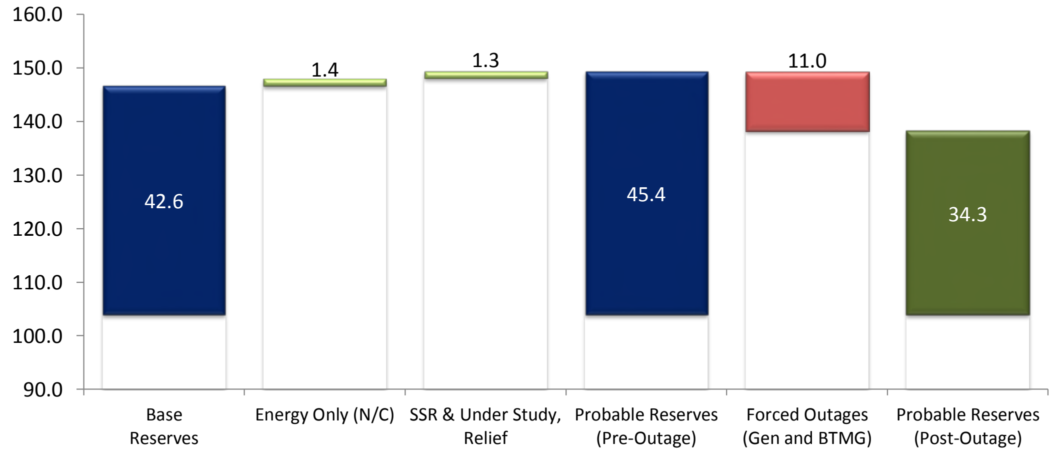


Figure 6.3-3: 2015-2016 Winter Rated Capacity projected Anticipated scenario (GW)

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2015-2016 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

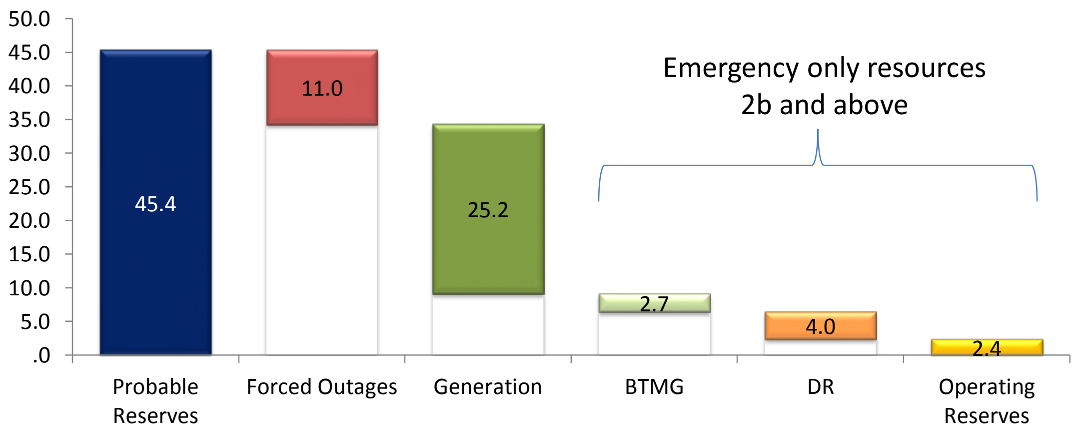


Figure 6.3-4: 2015-2016 Winter Rated Capacity projected Anticipated scenario reserves (GW)

The High Demand, High Outage scenario has added assumptions (Figure 6.3-5). Beginning with the anticipated reserves from the Anticipated scenario (Figure 6.3-3), the load increases to show the higher load from a 90/10 forecast. A higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available. An extreme forced outage rate is applied to the Extreme scenario, based on information from the polar vortex of the 2013-2014 winter.

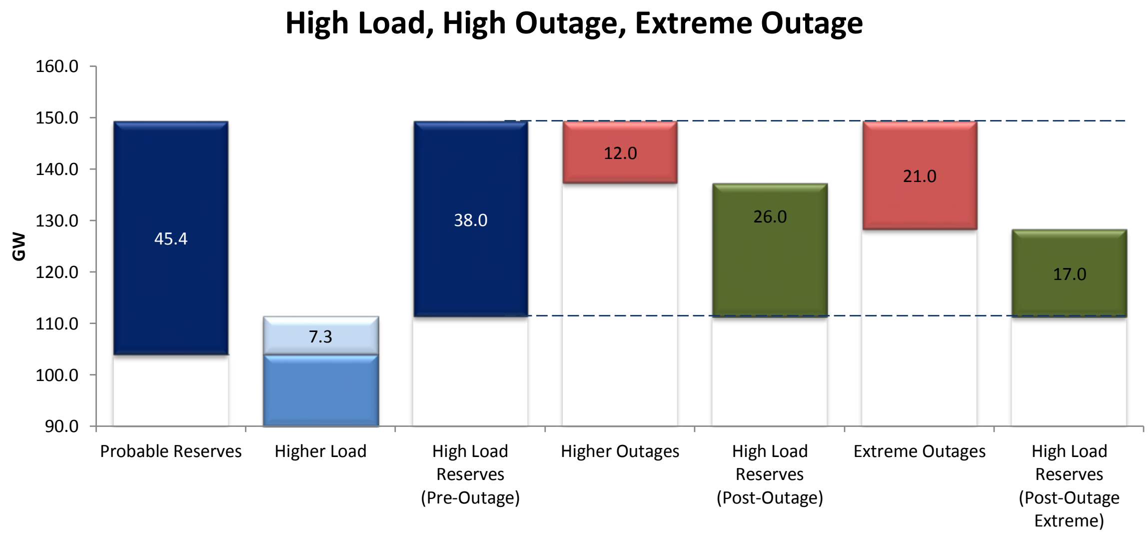


Figure 6.3-5: Winter Rated Capacity projected High-Demand, High-Outage scenario (GW)

2016 Summer Overview

For planning year 2016-2017, MISO's PRM is 15.2 percent. During the 2016 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 18.2 percent, which exceeds the requirement of 15.2 percent by 3.0 percentage points. The summer scenarios project the reserve margin to be in the range of 13.5 to 19.2 percent (Figure 6.3-7).

MISO's 50/50 coincident peak demand for the 2016 summer season was forecasted to be 125,913 MW including transmission losses, with 148,778 MW of capacity to serve MISO load. Excluded from the capacity are 2,874 MW of MISO South resources to align with the 876 MW intra-RTO contract path.

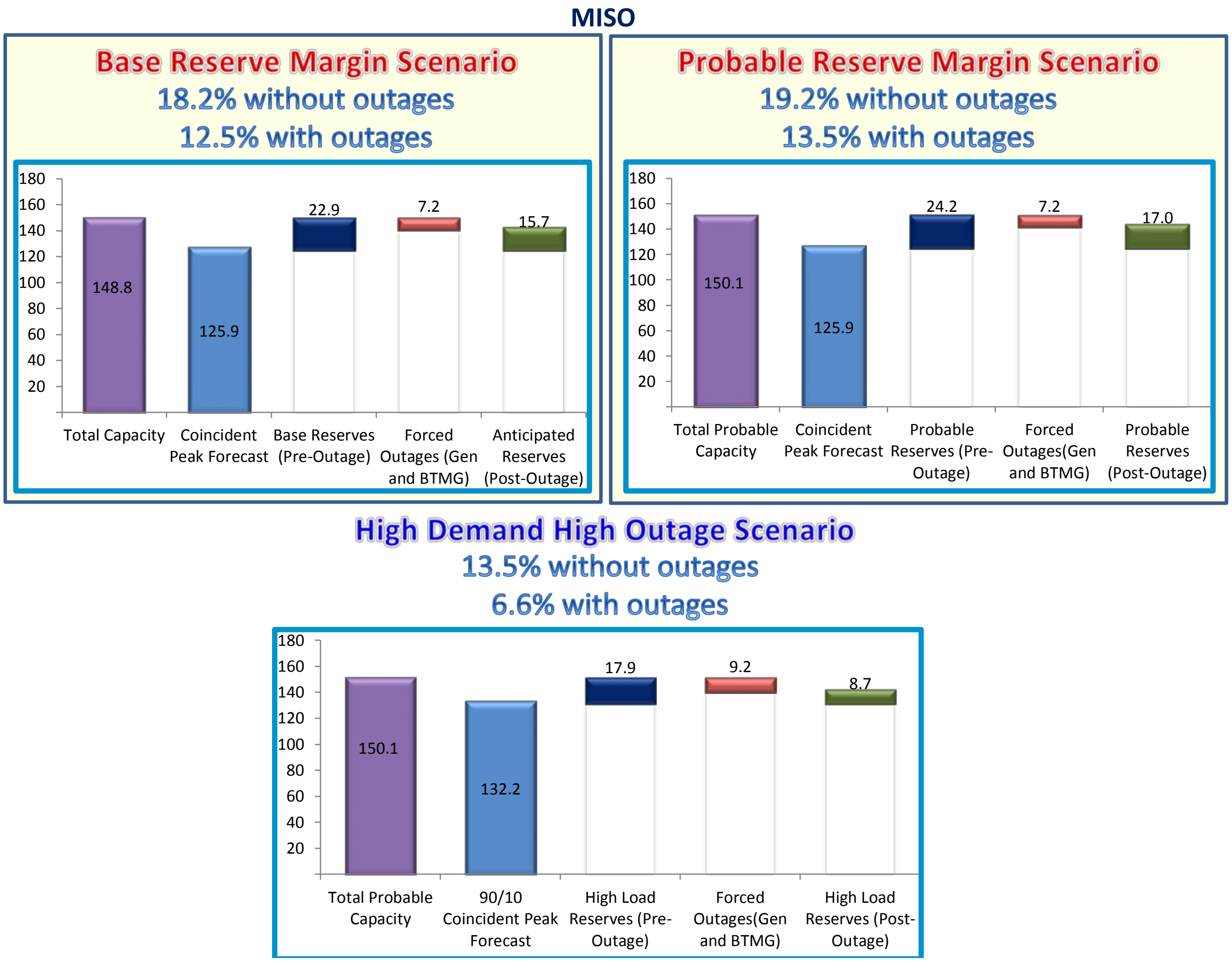


Figure 6.3-6: Summer 2016 Projected Reserve Margin scenarios

2016 Summer Rated Capacity

For 2016, MISO projected 148,778 MW of capacity to serve MISO load during the 2016 summer season. The capacity includes 3,724 MW of BTMG and 5,819 MW of DR programs, while including 965 MW of Net Firm Imports. MISO expected 1,773 MW of wind capacity to be available to serve load this summer, after discounting wind capacity in the Commercial Model with pending interconnection agreements and capacity with Energy Resource Interconnection Service without a firm point-to-point Transmission Service Request. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, 876 MW of excess capacity was assumed as transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (760 MW); thermal unit summer output reductions (12,031 MW); and reductions due to the Effective Load Carrying Capability of wind resources (12,031 MW). Also, any MISO South capacity over the total of South Load, South reserve margin requirement, and 1,000 MW of contract path was not included in the regional value. This means that 2,874 MW of MISO South excess capacity was excluded from the calculation to align with 876 MW contract path limitation.

Reserve Margin Scenarios

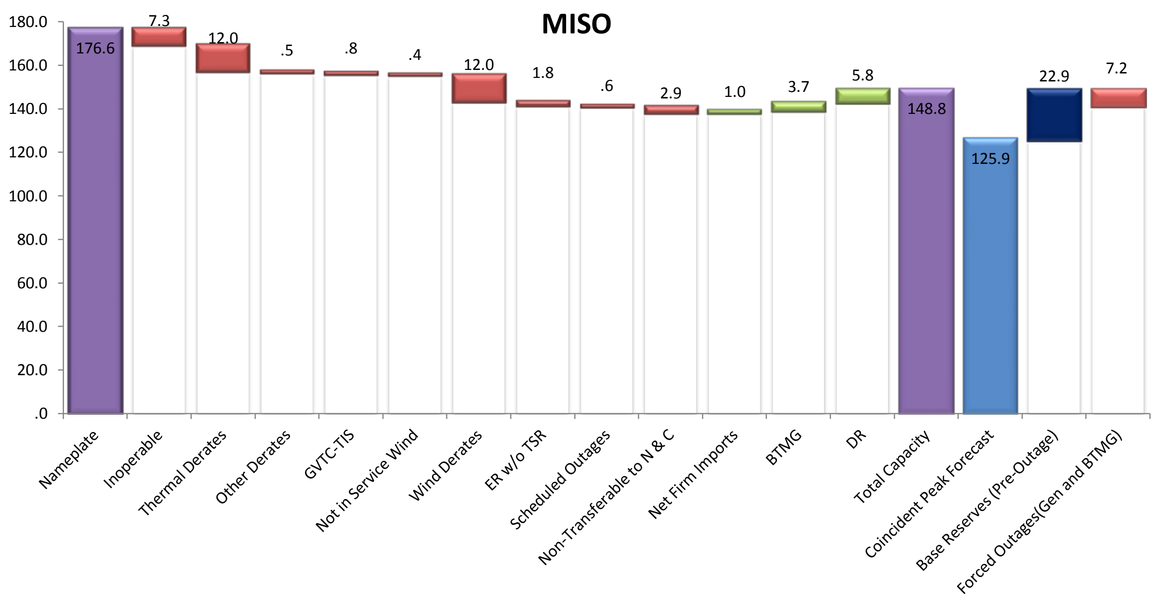


Figure 6.3-7: 2016 Summer Rated Capacity projected Base scenario (GW) showing the reduction from Installed Nameplate Resource Capacity. This includes derates and transmission limited resources.

The Probable scenario uses additional assumptions (Figure 6.3-9). MISO expects that any energy resource without firm point-to-point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 876 MW contract path limitation. Additionally, any units designated as Under Study through the Attachment Y process are considered available.

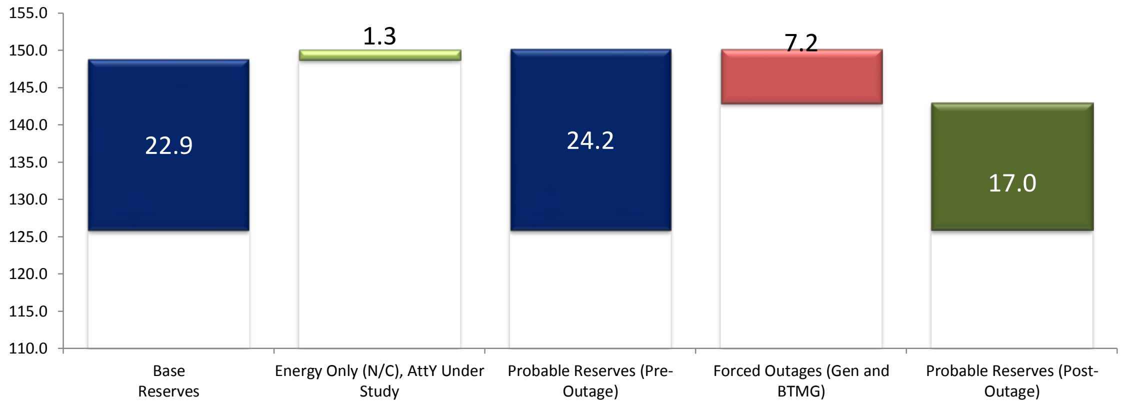


Figure 6.3-8: 2016 Summer Rated Capacity projected Probable scenario (GW), showing added capacity assumptions

The High Demand, High Outage scenario has added assumptions (Figure 6.3-10). Beginning with the Probable Reserves from the Probable Scenario (Figure 6.3-9), the load is increased to show the higher

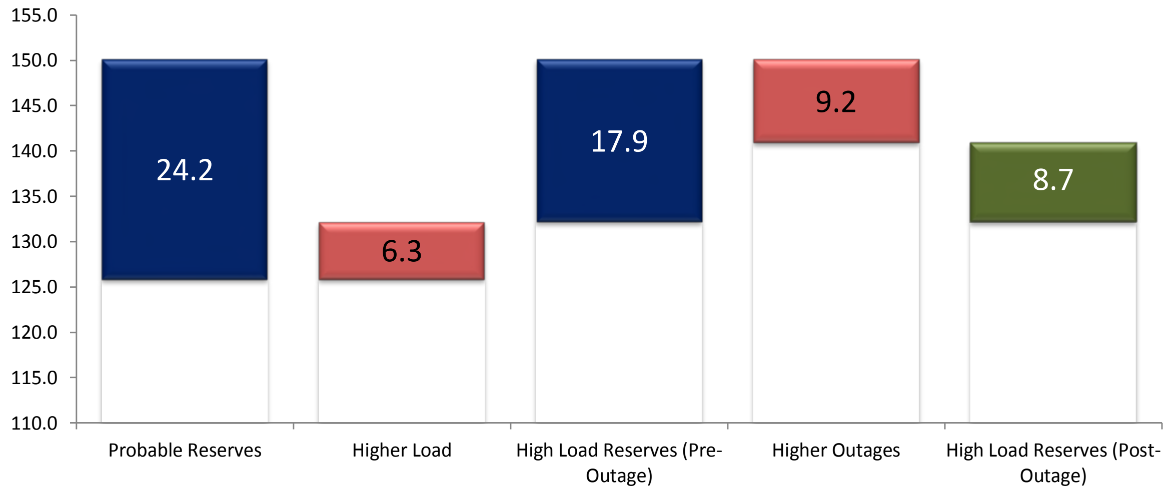


Figure 6.3-9: Summer Rated Capacity projected High Demand, High Outage scenario (GW)

2016 Summer Risk Assessment

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

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

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.3-10). As shown, the probabilistic analysis indicated a 72 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 10.5 percent chance of initiating

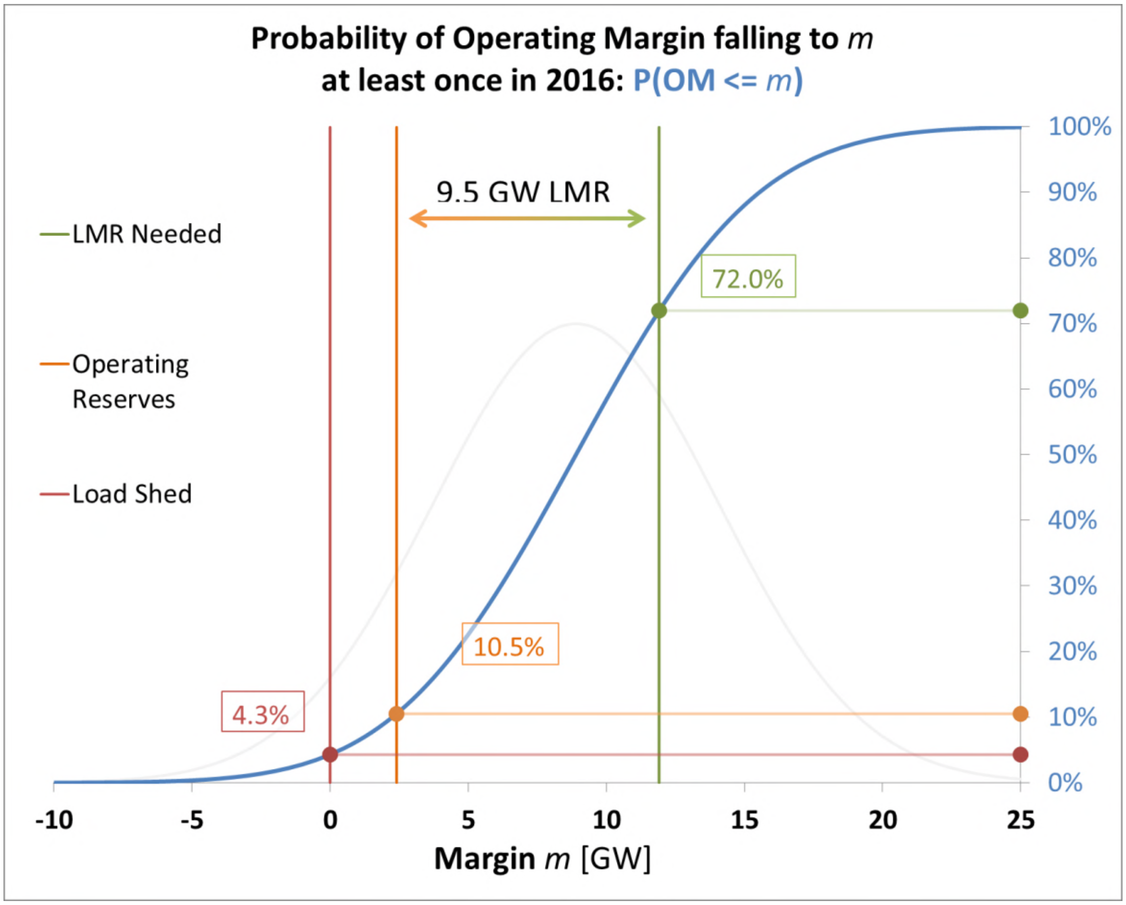


Figure 6.3-10: MISO 2016 summer chance of initiating Maximum Generation Emergency Step 2b or higher at forecasted Probable Reserve Margin

The reserves available in the Probable scenario are shown after forced outages are applied, showing the amount of Generation, BTMG, DR and Operating Reserves expected (Figure 6.3-11). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2016 summer season was 2,400 MW, which is called on as a last resort before load shed. Operating reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

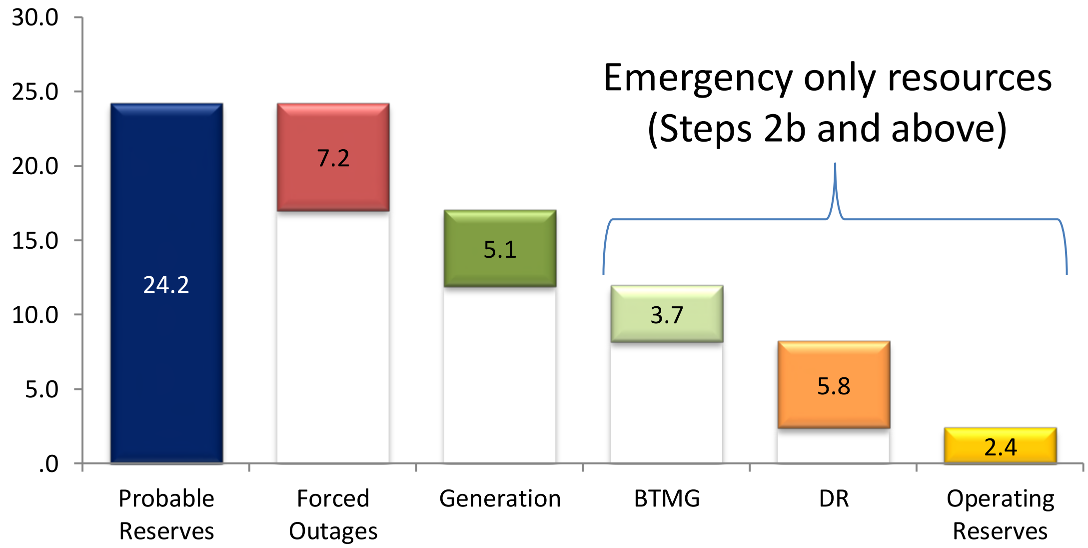


Figure 6.3-11: Summer Rated Capacity projected Probable Reserves (GW)

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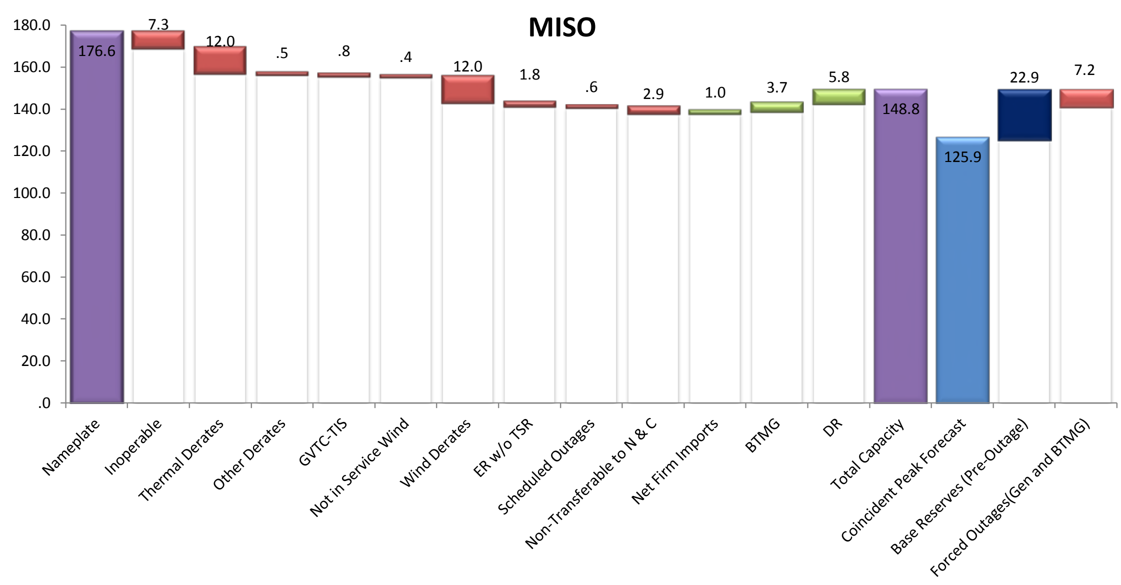


Figure 6.3-12: MISO 2016 Summer Rated Capacity waterfall chart, Base scenario (GW)

The calculation of MISO Summer Rated Capacity resources separates into 13 parts (Figure 6.3-12). Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2015-2016 Winter Resource Assessment. The 13 parts include:

1. *Nameplate*: the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable:* the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal Derates:* the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *Other Derates*: the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources (GVTC-TIS)*: the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind are the summation of differences in nameplate capacity and TIS.
6. *Not-in-Service and provisional wind*: units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind Derates*: the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *ER w/o TSR Energy-only:* resources with Energy Resource Interconnection Service (ERIS) without a firm point-to-point Transmission Service Right.
9. *Scheduled Outages*: Scheduled generator outages from June 1, 2016, through August 31, 2016, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler in March 2016. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."
   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.
   This calculation amounts to an expected scheduled maintenance of 619 MW.
10. Net Firm Exports: MISO anticipated the net firm interchange to be importing 965 MW for the 2016 summer.
11. *Non-Transferable to N&C*: 2,874 MW of MISO South resources were excluded from the available capacity to align with 876 MW intra-RTO contract path.
12. *Behind-the-Meter Generation (BTMG)*: the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2016-2017 Planning Resource Auction, 3,724 MW of BTMG cleared to be available for the 2016 summer season.
13. *Demand Resource*: MISO currently separates contractual demand resource into two separate categories: Direct Control Load Management (DCLM) and Interruptible Load (IL).
    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.
    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 5,819 MW for the 2016 summer season.

6.4 Demand Response, Energy Efficiency, Distributed Generation

Applied Energy Group (AEG) developed a 20-year forecast of existing, planned and technical potential demand response (DR); energy efficiency (EE) and distributed generation (DG) resources; and costs for MISO and the Eastern Interconnection regions modeled in economic planning. This study, completed in February 2016, is a refresh of the MISO 2009-2010 Demand Response and Energy Efficiency study.

This most-recent study added the South region, provided analysis at the local resource zone (LRZ) level, added DG programs, added behavioral programs and accounts for appliance standards, building codes, and programs not currently in use. This forecast meets both ongoing and emerging business needs.

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

In this report, the Existing Programs Plus case uses existing 2015 program data from the utility survey and assumes a small annual increase in participation in current programs through 2035 (0.5 percent increase each year; maximum 10 percent over 20 years). Savings are broken down by LRZ and different cases are analyzed in the full report. Summary results for the Existing Programs Plus cases are:

- Peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. Peak demand savings from DR, EE, and DG programs increase to 15 percent of the baseline summer demand by 2035.
    - On the residential side, appliance incentives, customer solar PV and customer wind turbines are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, custom incentives, prescriptive rebates and customer wind turbines are the programs with the greatest estimated impact by 2025.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 7 percent of the baseline annual energy in 2035. Throughout this forecast, energy savings come primarily from EE programs.
    - On the residential side, appliance incentives, customer wind turbines and whole-home audits are the programs with the greatest estimated impact by 2025.
    - On the commercial and industrial side, custom incentives, prescriptive rebates, and retro commissioning are the programs with the greatest estimated impact by 2025.
    - DG is a negligible percentage of these estimates with only a 0.6 percent cumulative effect by 2035.

At the scoping phase of this project, Clean Power Plan was in its draft form, which included energy efficiency as a building block. Hence, it made sense to include a specific 111(d) case in this study at that time. In this 111(d) 2014 case, to meet the compliance targets, the consultant assumed utilities would see significant peak demand savings starting with a slight ramp-up in 2018 to reach the EE goals in 2020[42].

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

Although the case specifically focuses on EE, AEG anticipates modest savings from demand response programs, as well. Savings are broken down by LRZ and different cases are analyzed in the full report.

Summary results (Table 6.4-1) for the 111(d) 2014 case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 27 percent of the baseline summer demand by 2035, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 7 percent of the baseline annual energy in 2035. Throughout this forecast, energy savings come primarily from EE programs.

Additionally, at the scoping phase of this project, MTEP16 futures definitions included high-demand and low-demand futures. The high-demand future captured the effect of increased economic growth, whereas the low-demand future captured the effect of decreased economic growth. AEG provided estimates for savings under both those future definitions.

Summary results for the high-demand future case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 20 percent of the baseline summer demand by 2035, relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 9 percent of the baseline annual energy in 2035.

Summary results for the low-demand future case are:

- Similar to the Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 13 percent of the baseline summer demand by 2035 relative to the 15 percent in the Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 6 percent of the baseline annual energy in 2035.

MISO	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
	2015	2016	2017	2025	2035	2015	2016	2017	2025	2035
Baseline Projection	118,235	119,349	120,058	126,174	136,441	678,651	685,467	690,015	732,076	801,747
Existing Programs Plus Case Savings	6,326	6,900	7,466	12,481	20,263	3,221	5,326	7,447	25,314	53,225
Existing Programs Plus Case Savings %	5%	6%	6%	10%	15%	0%	1%	1%	3%	7%
CPP 111(d) Savings	6,326	6,900	7,466	19,408	36,495	3,221	5,326	7,447	54,458	124,709
CPP 111(d) Savings %	5%	6%	6%	15%	27%	0%	1%	1%	7%	16%
High Demand Savings	6,326	7,049	7,763	14,522	27,350	3,221	5,470	7,786	29,078	69,800
High Demand Savings %	5%	6%	6%	12%	20%	0%	1%	1%	4%	9%
Low Demand Savings	6,326	6,882	7,405	11,466	17,259	3,221	5,309	7,375	23,406	46,119
Low Demand Savings %	5%	6%	6%	9%	13%	0%	1%	1%	3%	6%

Table 6.4-1: MTEP16 futures

In addition to the MTEP16 future definition cases, AEG was also tasked with providing an estimate of DG programs and their impact on peak demand and annual energy savings. The primary driver for this DG related analysis was Organization of MISO States' (OMS) request for additional DG analysis, as well as general trends in the industry pointing towards decrease in solar PV and battery storage costs. Hence, the consultant looked at increases in customer-cited solar PV, wind, CHP, battery storage and thermal storage. AEG created two levels of increased distributed generation (Table 6.4-2):

- Demand-side DG, which assumed a ramp-up to reach specific solar targets, battery storage targets, or increased growth in wind, CHP and thermal storage
- High-penetration DG, which assumed a theoretical upper-limit that reflected 100 percent participation in DG.

Summary results for the demand-side DG case are:

- Similar to Existing Programs Plus case, the peak demand savings from DR programs are 5 percent of the baseline summer demand in 2015. However, peak demand savings from DR, EE and DG programs increased to 22 percent of the baseline summer demand by 2035 relative to the 15 percent in Existing Programs Plus case.
- Annual energy savings are 0.5 percent of the baseline annual energy in 2015. Annual energy savings increase to 10 percent of the baseline annual energy in 2035.

Summary results for the high-penetration DG case are:

- The peak demand savings from DR, EE and DG programs increased to 46 percent of the baseline summer demand by 2035 relative to the 22 percent in demand-side DG case.
- The annual energy savings increased to 20 percent of the baseline annual energy in 2035 relative to the 10 percent in demand-side DG case.

MISO	Peak Demand (MW) baseline					Annual Energy (GWh) baseline				
	2015	2016	2017	2025	2035	2015	2016	2017	2025	2035
Demand side DG Savings	6,373	6,998	7,619	15,068	30,173	3,423	5,740	8,083	33,608	83,968
Demand side DG Savings %	5%	6%	6%	12%	22%	1%	1%	1%	5%	10%
High Penetration DG Savings	6,373	11,348	14,097	35,613	62,207	3,423	14,769	21,617	77,869	156,870
High Penetration DG Savings %	5%	10%	12%	28%	46%	1%	2%	3%	11%	20%

Table 6.4-2: DG Case

The industry is increasing its focus on initiatives that include DR, EE, and DG in order to meet federal or state policy requirements and other enacted or emerging environmental regulations. MISO needed to refresh its models for DR and EE and explicitly include DG for modeling of future transmission capacity as well as understand the potential and cost of these programs both internally and for its stakeholders.

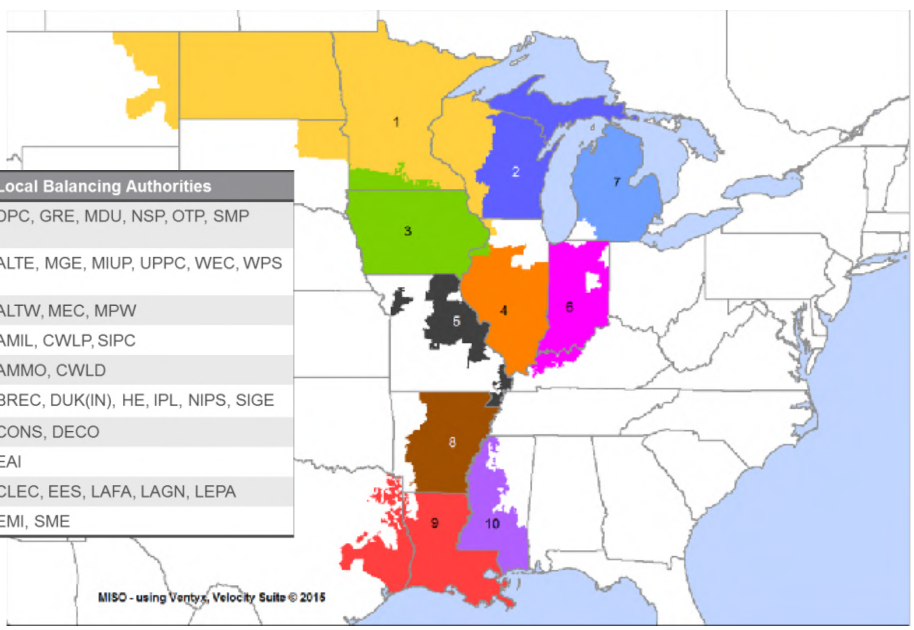
This forecast allows MISO to analyze the impacts related to DR, EE, and DG programs for transmission planning, real-time operations, and market operations (including resource adequacy). This forecast positions MISO to understand emerging technologies and the role they will play in transmission planning as there is a specific case on distributed generation both at a base case level and increased penetration level. Additionally, this forecast was incorporated into the Independent Load Forecast models by providing the “net” forecasts.

6.5 Independent Load Forecast

MISO procured an independent vendor, State Utility Forecasting Group (SUFG), to develop three 10-year horizon load forecasts[43]. SUFG provides data used to develop an independent regional load forecast for the MISO Balancing Authority (BA). The first 10-year forecast (2015-2024) was delivered in November 2014; the second (2016-2025) was delivered in November 2015; the third (2017-2026) was due November 2, 2016.

SUFG produces econometric models for 15 MISO states. The independent load forecast includes annual energy demand and a seasonal (summer and winter) peak forecast on a non-coincident basis with the MISO system peak for MISO and each of the 10 local resource zones. The long-term forecast will be based on MISO Business as Usual (BAU) planning future each year.

The base independent load forecast will be a 50/50 forecast, meaning there is a 50 percent probability that the load will be either higher or lower than the forecasted value. The load forecast (demand and energy) for the MISO BA will be forecasted for each state, and then aggregated into each MISO Local Resource Zone (LRZ) using state allocation factors. The MISO BA has 36 Local Balancing Authorities (LBA). The LBAs are aggregated into 10 Local Resource Zones (LRZs) (Figure 6.5-1).



LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMI, SME

Figure 6.5-1: MISO LRZ Map for Planning Year 2016.

The independent load forecast is not intended to replicate or replace an individual Load Serving Entity (LSE) or Transmission Owner (TO) forecast. This is an independent and transparent approach to develop a MISO load forecast that relies on publically available data. This limits dependence on confidential or

[43] https://www.misoenergy.org/Planning/Pages/IndependentLoadForecasts.aspx

vendor data and new data requests. Each state forecast model and the associated assumptions will be made available to stakeholders, and will require no vendor-specific software. SUFG is using common industry econometric forecast data and software (Global Insight, EViews).

Project Schedule and Deliverables

This project is a three-year effort (Figure 6.5-2), with forecast deliverables due annually at the beginning of November 2014, 2015 and 2016. Key activities and milestones are outlined for the 2017-2026 forecast (Table 6.5-1).

MISO made progress on a load forecast comparison between the Independent Load Forecast and the Aggregated LSEs Forecast. The objective of this comparison is to identify where the forecasts differ in order to determine if model, methodology or inputs can explain these differences. The load forecast comparison does not test whether one forecast is more accurate than the other; the goal is to understand where and why there are differences. Data inputs that explained some of the differences were identified. MISO used historical energy and demand data from 2010 to 2014 to attempt to put forecast starting points and trends in perspective. Since forecasts assume normal weather, this MISO historical data was then weather normalized so that historical data without the effects of weather would be available.

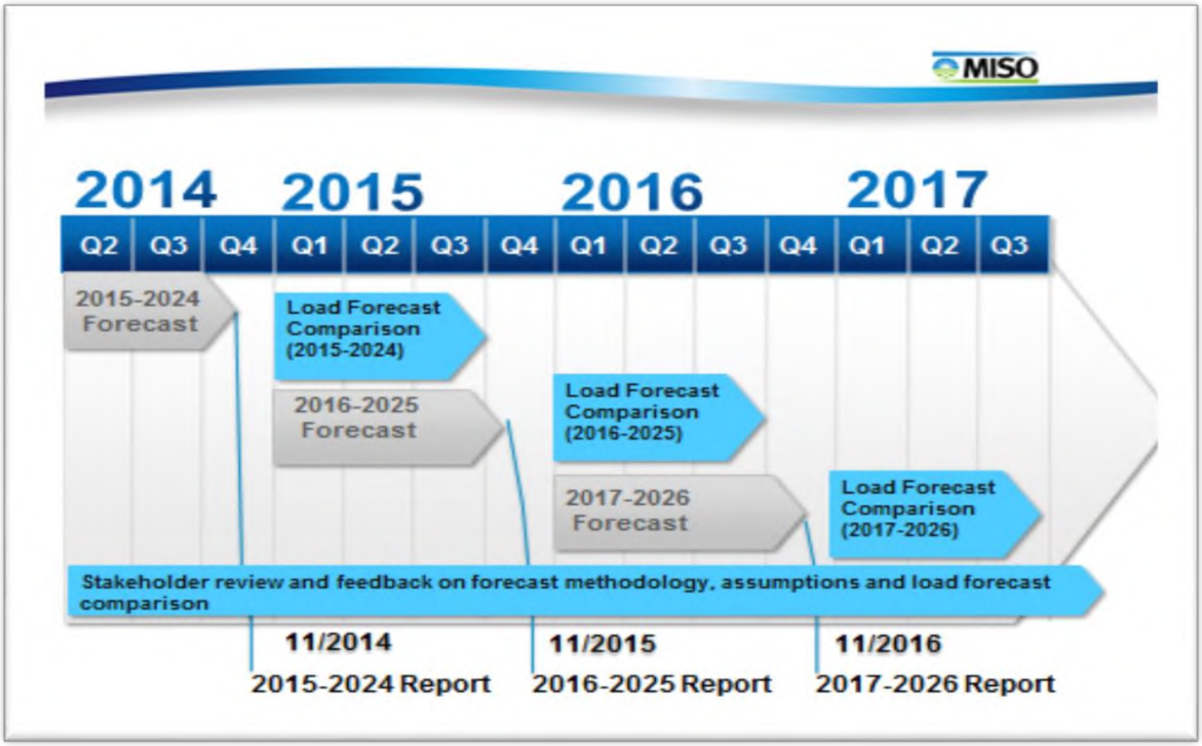


Figure 6.5-2: Independent Load Forecasting Project high-level schedule

KEY ACTIVITIES COMPLETE AND MILESTONES	TARGET DATE
2017-2026 Independent Load Forecast	**11/1/2016**
Stakeholder Workshop #1 – Review 2016 project plan, discuss potential improvements, next steps	1/18/16
Stakeholder Comments on Potential improvements Due	2/8/16
Acquire (update) state level historical data	March 2016
Update econometric forecasting models for each state	April 2016
Stakeholder Workshop #2 - Load forecast comparison	4/18/2016
Stakeholder Workshop #2 Comments Due	5/9/2016
Determine allocation factors to convert state energy forecasts to each Local Resource Zone forecast, Incorporate econometric model drivers	6/2016
Review energy to peak demand conversion model for each Local Resource Zone, Generate a 10 year annual energy forecast for each state using its econometric forecast model	7/2016
Stakeholder Workshop #3, Eagan	July 25, 2016
Stakeholder Workshop #3 Comments Due	August 15, 2016
Determine 10 year annual energy forecast for each Local Resource Zone	8/2016
Determine 10 year seasonal peak demand for each Local Resource Zone	8/2016
Determine MISO's 10 year forecast for annual energy and seasonal peak demand	9/2016
Stakeholder Workshop #4 - Review 2016-2025 Forecast results, Carmel	September 26, 2016
Stakeholder Comments Workshop #4 Due	3 weeks after
Doug's presentation to Oct Planning Advisory Committee (PAC)	October 19, 2016
Independent 10 year (2016-2025) Demand and Energy forecast report completed	11/1/16
Doug's presentation to Nov Planning Advisory Committee (PAC)	November 16, 2016

Table 6.5-1: Independent Load Forecasting project detailed project schedule, 2016.

Project Justification

The MISO transmission system needs to be planned such that it is prepared for changes in the resource mix caused by changing environmental regulations, commodity prices, renewable integration and economic conditions.

More than 141 LSEs and approximately 41 TOs submit demand forecasts annually, each with potentially different assumptions and methodologies. Each LSE and TO uses its own parameters, making it impossible to develop a MISO region-wide load forecast based on a common set of economic conditions for scenario analysis in long-term studies. An unaccounted-for deviation in a load forecast can result in increased reliability risk from the industry reliability standard (one day in 10 years) because it is difficult — if not impossible — to understand the drivers and changes in an aggregated bottom-up, long-term forecast.

A single, MISO region-wide load forecast can be viewed as a top-down approach for the region; it has the benefits of one set of assumptions, and can be used in other regional studies and future analysis. This top-down approach for load forecast fits in with MISO's Top-Down, Bottom-Up transmission planning process.

This is an alternative forecast methodology. It is not intended to replicate or replace each LSE's or TO's forecast process. MISO will continue to use the load forecasts provided by the LSEs and TOs in MTEP and Module E: Resource Adequacy as required by the MISO Tariff.

Book 3
Policy Landscape

2016

Policy Landscape Overview

The MISO generation fleet continues to evolve. Driven by both economics and environmental regulations, the MISO region as a whole is transitioning from a primarily coal-fueled fleet to a balance of coal, natural gas and renewables.

While the evolution of the fleet is generally accepted across the industry, the rate at which the transition will occur is uncertain. In the past 10 years, MISO has seen a significant increase in wind generation as well as coal retirements. Largely driven by compliance with the Mercury and Air Toxics Standards, which went into effect on April 16, 2015, approximately 10 GW of coal capacity in MISO has recently retired or converted fuel. Retired capacity has partially been replaced by natural gas and wind units; however, capacity additions have not kept pace with reductions. In the past five years, planning reserve margins[44] have dropped from 23 percent and above to 18 percent (Section 6.2).

Geographic diversity, policies (both existing and pending) as well as economics impact different areas of the footprint to different degrees. The MISO North and Central regions' fleet, which is primarily coal-based, continues to receive pressure from environmental regulations, competition from natural gas and age. Currently, the average age of the MISO North and Central regions' coal fleet is 40 years old. Analysis shows that coal plants typically retire at 65 years, meaning approximately 8 GW of currently unannounced coal retirements are expected in the next 15 years. That value could potentially triple depending on carbon regulations (Section 7.1).

The MISO North and Central Regions continue to see a large potential for increased wind on the system. As of June 2016, approximately 16 GW of wind currently operates in the MISO footprint and another 30 GW is currently in the Generator Interconnection Queue, 10 GW of the queued wind is in Iowa. MISO's South Region is primarily fueled by natural gas units so fuel prices, age, and demand and energy growth rates are the significant factors that affect the southern fleet. Approximately 12 GW of MISO South Region natural gas and oil units are at risk of age-related retirement within the next 15 years. While the current Generator Interconnection Queue indicates that most of the aging natural gas units will be replaced with newer natural gas units, it's also expected that demand-side resources as well as solar will play a greater role in the fleet into the future.

As MISO looks forward, it expects the trends towards a lower carbon fleet to be driven by potential carbon regulations, age, sustained low natural gas prices, declining construction costs of renewables and renewable tax credits. While currently the EPA's Clean Power Plan is stayed, multiple states and companies have stated they will continue to pursue carbon reductions. Should the Clean Power Plan or equivalent regulation become active, MISO's Clean Power Plan analysis shows that approximately 16 GW of additional coal capacity is at risk of retirement (Section 7.1). The replacement plan for retired capacity includes a combination of renewables, natural gas and demand-side technologies.

Even without carbon regulations, MISO expects economics to drive the continued trends towards more renewables. The capital cost for onshore wind is projected to decline annually by approximately 0.4 percent and by approximately 3 percent for PV solar units. In addition, the Production Tax Credit extension and Investment Tax Credit are projected to make renewables more economically competitive with thermal units (especially under scenarios where carbon reduction targets are assumed). To date,

[44] As a percentage of installed capacity

renewables have been built in the anticipated locations that utilize the outlet provided by MISO's Multi-Value Project Portfolio. However, as the footprint gains additional wind above and beyond Renewable Portfolio Standards, and as hub heights increase, there is greater potential that wind generation will be developed in areas outside of the traditional corridors, such as in the MISO South Region. Solar also continues to increase in economic viability.

In addition to generation fleet changes, demand response and energy efficiency are projected to play a more significant role in the future resource adequacy. Currently, approximately 5 GW of demand response participates in the MISO market. Driven by economics, public policy and new technologies, there is a potential for 8 to 11 GW of demand response by 2031 in the footprint (Section 6.4), which is dependent on out-year demand and energy levels as well as public policy. In addition, energy efficiency is projected to decrease annual energy by 12,000 to 38,000 GWh in 2031.

MISO continues to monitor trends in emerging alternative technologies such as storage and distributed generation to both understand and plan for the potential that these technologies will impact the transmission system.

MISO currently has one utility-scale battery on the system with two additional installations totaling an additional 50 MW in the Generator Interconnection Queue. MISO continues to work with the Organization of MISO States to better understand the potential and impacts of higher penetrations of demand-side alternatives.

The following sections detail studies designed to understand and integrate both current and potential public policies. Section 7.1 explores how changing regulations from the U.S. Environmental Protection Agency may impact the electric system going forward, while section 7.2 examines the value of the Multi-Value Projects under current planning assumptions. Both of these sections look at how changing economic and policy conditions impact the electric system to provide insight into the risks and value created by these changes.

Chapter 7

Regional Studies

2016

7.1 EPA Regulations

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

Some of the main regulatory drivers are developed by the U.S. Environmental Protection Agency (EPA) and include the Mercury and Air Toxics Standards (MATS), the National Ambient Air Quality Standards (NAAQS), the Clean Power Plan[45] (CPP) and the Cross-State Air Pollution Rule (CSAPR). This year, MISO analyzed the effects of two of these regulations: the CPP and the proposed CSAPR update.

MISO's Clean Power Plan Analysis

Purpose of MISO's CPP Analysis

The EPA designed its CPP to regulate carbon dioxide (CO_2) emissions from the electric power sector, with a goal of a 32 percent reduction in CO_2 emissions from 2005 by 2030. This rule could affect the industry in a number of significant ways. Advised by input from its stakeholders, MISO analyzed the CPP in order to provide its member states and asset owners with independently derived technical data and other objective information they may wish to consider in preparing their CPP implementation plans.

By design, MISO's stakeholder-informed analysis also examined how industry trends and drivers other than the CPP — such as low natural gas prices and an increasing penetration of renewable generation — cause the region's resource portfolio to evolve. MISO expects that these non-CPP policy and economic drivers will continue to reshape the electricity industry regardless of whether the CPP survives the legal challenges it currently faces. These non-CPP drivers figured prominently in MISO's analysis, effectively making it a study about the broader drivers of the evolving resource portfolio.

The observations in this section are not recommendations for complying with the CPP or addressing the non-CPP factors contributing to the region's evolving resource portfolio. Instead, these observations are intended to help MISO's stakeholders better understand how the CPP and the non-CPP drivers could impact the MISO system. States, utilities and other entities should consider these observations within the broader context of their CPP compliance objectives, policy goals and views about their desired future resource mixes.

The U.S. Supreme Court Stay and Ongoing CPP Litigation

On Feb. 9, 2016, the U.S. Supreme Court stayed the CPP until the litigation challenging it runs its full course. Because of the stay, some MISO-member states scaled back or stopped working on CPP-related matters.

At the time of the stay, MISO had largely finished its CPP analysis, although some of the study's findings had not been released. Since then, MISO has worked closely with its stakeholders to determine how potential CO_2-reduction initiatives will be reflected in MISO's transmission-planning efforts going forward.

[45] For the Clean Power Plan Final Rule Study full report

Study Focus and Key Observations

Near-Term Analysis

All of the key observations cited are derived from the "Near-Term" phase of MISO's analysis, which focused on assessing the impacts of complying with the CO_2-reduction targets in the CPP rule itself. This phase was conducted using scenario-based evaluation on static resource mixes that allowed for detailed observations in some areas, but limited the ability to make observations with regard to the most cost-effective resource build-out to achieve compliance.

One primary focus of this analysis is to compare and contrast potential impacts associated with two different approaches to CPP compliance: (1) rate-based compliance, and (2) mass-based compliance[46] on a regional MISO-wide level, as well as on a state-by-state basis.

On the regional level, the analysis yielded the following key observations about the rate/mass compliance options and other related matters:

- Regionally, mass-based compliance is less expensive than rate-based compliance, with the gap between the two approaches increasing over time, unless the construction of non-CO_2-emitting resources can keep pace with the demand for emission rate credits (ERCs) needed by existing fossil-fueled resources to continue compliant operation.
- Early compliance targets can be met through existing renewable portfolio standards and coal-to-gas re-dispatch, but comprehensive planning would need to start expeditiously to meet increasingly stringent compliance targets in the mid-2020s.
- Under the CPP, the coal fleet faces increased risks of decreased generation and operating hours, along with increased cycling.
- A robust build-out of new, non-CO_2-emitting resources would be needed to mitigate CO_2 price increases under rate-based compliance.
- System dispatch faces relatively less change under mass-based compliance, and thus may require less capital investment.
- Regional, trading-ready compliance approaches yield lower-cost compliance than state-by-state compliance options.

MISO also analyzed how individual states in the MISO region could be affected by choosing either the rate-based or the mass-based compliance option. From this part of the analysis, MISO made the following key observations:

- Generation will likely rise/fall in similar locations under both rate and mass compliance approaches. Transmission expansion, if needed, will likely be similar under both.
- Mass-based compliance produces a more balanced mix of buyers and sellers within MISO.
- Most states see a mass-based compliance advantage unless a regional heavy penetration of renewables and energy efficiency is achieved. Because MISO assumed a static resource mix, the ERCs created by renewables and energy efficiency are assumed to be available for use in compliance. If, however, these resources fail to generate the ERCs necessary for cost-effective rate-

[46] Rate-based compliance entails limiting how much CO_2 is emitted per every megawatt-hour of energy produced in a given state or region, while mass-based compliance entails limiting how much total CO_2 is emitted in a state or region over a set amount of time, such as a one-year period.

based compliance, there is a risk that costs will increase far beyond costs of mass-based compliance. Rate-based states may consider the need to mitigate this risk should it come to fruition.

- Under a "patchwork" mix of both rate and mass compliance, states with a rate advantage may lose that benefit if other states go mass.

Overall, MISO's analysis shows that flexibility in compliance options leads to lower compliance costs. Individual states and regions derive different benefits from pursuing different options, but working together as a region allows each state to share this diversity in a way that benefits the entire region. MISO as a regional system operator and transmission planner provides the flexibility needed to integrate these preferred compliance options while maintaining reliability and keeping costs low.

Mid-Term Analysis

MISO also conducted a "Mid-Term" phase of analysis that looked more broadly at how the region's generation assets could be impacted by various CO_2-reduction scenarios that are not based specifically on the CPP, but rather on the non-CPP policy and economic drivers that cause the resource portfolio to evolve. This phase aimed to identify the optimal resource expansion and retirements using mass-based compliance under several CO_2 reduction strategies. MISO's analysis produced two primary results: (1) potential coal retirements in the region, and (2) the potential to build out the region's renewable energy resources. This phase modeled the study region into the year 2035, with emission reduction targets continuing through the entirety of the study period.

Coal retirements: MISO analyzed how much of the region's existing coal-fired generation may likely retire for economic reasons under the CPP rule as written, as well as two hypothetical CO_2-reduction targets:

- The Partial CPP Future: Assumes that the region's power-sector CO_2 emissions will decline by 17 percent by 2030 compared to a 2005 baseline. This future models how the region could be impacted if states and generators begin to comply with the CPP, but full compliance is slowed or halted due to legal or political challenges to the rule (Note: This future, like all of the others in MISO's analysis, was developed before the U.S. Supreme Court stayed the CPP).
- The Accelerated CPP Future: Assumes that the region's power-sector CO_2 emissions will decline by 43 percent by 2030 compared to a 2005 baseline, driven by low natural gas prices and decisions by states and generators to aggressively build out renewables and demand-side resources. The 43 percent figure is based on more aggressive CO_2-reduction plans, such as the midterm compliance point of the Waxman-Markey climate change bill that the U.S. House of Representatives passed in 2009. This future also helps to illustrate how things may change if the EPA tightens the CPP targets during a rule review at some future date.

Using these scenarios, MISO modeled how much — or how little — each of the region's existing coal units would run to help the MISO system as a whole to meet the different CO_2-reduction targets.

MISO's key observations regarding coal retirements: MISO's analysis indicates that retiring coal units from service could cause total system costs"[47] to decline for each future studied. For example, total system costs for the Partial CPP Future reach their lowest range when 8 to 11 GW of coal is retired, climbing to 24 to 30 GW for the Accelerated CPP Future. Under the CPP rule itself, MISO's analysis indicates that total system costs would reach their lowest point with 16 to 21 GW of coal retirements. Given the similar costs within this range, 16 GW of coal retirements is seen as a likely outcome.

[47] As used here, the term "total system costs" includes the following: (1) generation production costs, (2) generation capital costs and (3) generation annual fixed operations and maintenance (O&M) costs. It does not include sunk costs of retired coal units nor electric transmission or natural gas transportation costs.

Notably, MISO's analysis also indicates that total system costs in all three scenarios start to climb again at a certain level of coal generation retirements. At this level, the costs of building and operating new gas-fired and renewable resources start to exceed the costs of continuing to operate existing coal units.

Build-out of renewables: MISO's analysis indicates that a near-equal mix of wind and combined-cycle plants would likely replace coal units as they retire under the CPP. When greater CO_2 reductions are examined, the proportion of wind (compared to combined cycle) replacing coal increases, and solar resources become more viable. This renewable generation is in addition to what would be built without a national CO_2-reduction policy. This leads to the need to understand where this additional renewable generation would likely be sited and constructed. A separate effort was undertaken to analyze where these new wind and solar resources would likely be sited. This effort looked at levels that are more stringent than those of the CPP, in part because MISO wanted to understand the "upper bounds" of viable levels of wind and solar in the region.

MISO's key observations regarding build-out of renewables: MISO's analysis indicates that much of the additional wind would likely first be built in areas that currently experience high levels of wind buildout such as Iowa, Minnesota and Michigan. Significantly larger amounts of new wind and solar capacity would need to be built if far more aggressive CO_2 reductions of 50 percent or 80 percent are pursued in the region. The analysis indicates that the optimal locations for building this new wind power would be concentrated in eastern Montana, the Dakotas and the Great Lakes region, given the higher wind potential in those areas. Notably, these areas are not particularly close to MISO's biggest load centers. However, if the objective is to reduce CO_2 emissions aggressively in the region, MISO's analysis indicates that it would still be cost-effective to site new wind power in these relatively remote areas and build new transmission to deliver the energy to the rest of the MISO footprint.[48]

Conclusion

MISO's analysis of the CPP, along with industry trends and other studies, indicates that the future will bring significant change to the power sector. The CPP accelerates this change by driving increased levels of renewable and energy efficiency deployment, and by pushing up the retirement timelines for coal assets. This study looks at a range of compliance options and impacts to the generation and transmission assets within the MISO footprint. Compliance costs are found to vary greatly with the price of natural gas along with the economic and technical potential of both renewable and energy efficiency deployment throughout the study period. Going forward, analysis (including interregional analysis) is required to assess the transmission and natural gas infrastructure needs associated with this industry-wide shift. Future analysis will also require more consideration of energy efficiency as a compliance mechanism, as it can prove a viable means of ERC-creation under rate-based compliance. The results of this study will be used to inform our strategic transmission assessment starting in the fall of 2016. It is crucial that planning efforts continue given the long lead time needed to plan, approve and build the infrastructure necessary to enable the cost-effective and reliable evolution of the electric system.

MISO's Analysis of the EPA's Proposed CSAPR Update

On November 16, 2015, the EPA proposed the CSAPR Update Rule to address interstate transport of air pollution under the 2008 ozone NAAQS. Effective beginning in 2017, the proposal reduces seasonal (May 1-September 30) nitrogen oxides (NO_x) emissions from power plants in 23 eastern states, 11 of which are in the MISO footprint.

[48] For the full report on MISO's study on the build-out of renewables, see https://www.misoenergy.org/Events/Pages/MTEP17Futures20160428.aspx "MTEP17 Futures Development Workshop Vibrant Clean Energy Report and Documentation."

MISO analyzed the proposed CSAPR Update Rule to understand near and long-term impacts to generating resources in the MISO. The primary focus was to evaluate the ability of affected states to meet their updated seasonal NO_x budget limits with and without trading of allowances, particularly in 2017. Key observations of the analysis are:

- The more stringent targets of the CSAPR Update Rule can be met through system re-dispatch with or without trading in 2017 and beyond, though regional energy and emission trading eases implementation in MISO
- Generation shifts in the fuel mix indicate coal-to-gas re-dispatch, though in aggregate, these shifts are small even in 2017
- Total generation in MISO states increases, including in those states not covered under the CSAPR Update Rule, to balance decreases elsewhere in the Eastern Interconnection
- MISO states in sum perform better than the combined emissions target when each covered state participates in emissions allowance trading

MISO also analyzed the proposed CSAPR Update Rule under 2030 assumptions to evaluate its interaction with a full implementation of the CPP. Results indicate the additional constraint of the proposed CSAPR Update Rule does not significantly alter how MISO performs under CPP compliance. Generation trends continue with coal-to-gas re-dispatch and the CO_2 price is relatively unaffected with the more stringent seasonal NO_x emission constraint.

The EPA issued the final CSAPR Update Rule on September 7, 2016. MISO's analysis occurred prior to this date, and thus focused on the proposed CSAPR Update Rule. In the final rule, total allowable emissions are greater than in the proposed rule update, but this can vary from state to state.

7.2 MTEP16 MVP Limited Review

The MTEP16 Multi-Value Project (MVP) Limited Review provides an updated view into the projected congestion and fuel savings of the MVP Portfolio. The MTEP16 MVP Limited Review's business case is on par with the review of the original business case in MTEP11. Consistent with previous reviews, the MTEP16 Limited Review provides evidence that the MVP criteria and methodology works as expected. The MTEP16 analysis shows that projected MISO North and Central region benefits provided by the MVP Portfolio are comparable to MTEP11, the analysis from which the portfolio's business case was approved.

The MTEP16 results demonstrate that the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.0 to 2.7; consistent with the 1.9 to 2.8 range calculated in MTEP15
- Creates $10.5 to $35.8 billion in net benefits (using MTEP14 benefits for all categories besides congestion and fuel savings) over the next 20 to 40 years, an increase of up to 26 percent from MTEP15

Increased benefits related to the congestion and fuel savings are largely driven by natural gas price assumptions and wind energy modeling.

The MTEP16 MVP Limited Review Business Case will be posted under the Multi-Value Project Portfolio Analysis section of the MISO website.

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

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

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

MISO conducted its second limited MVP Portfolio review, per tariff requirement, for MTEP16. The MVP Review has no impact on the existing MVP Portfolio's cost allocation. MTEP16 Review analysis is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.
The MVP Review uses stakeholder-vetted MTEP16 models and makes every effort to follow procedures and assumptions consistent with the MTEP15 analysis. Consistent with previous MTEP MVP Reviews, the MTEP16 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in service and those still being planned. Because the MVP Portfolio's costs are

allocated solely to the MISO North and Central regions, only MISO North and Central Region benefits are included in the MTEP16 MVP Limited Review.

Economic Benefits

MTEP16 analysis shows the MVP Portfolio creates $21 to $57.3 billion in total benefits[49] to the MISO North and Central Region members (Figure 7.2-1). Total portfolio costs have slightly increased from $6.46 billion in MTEP15 to $6.47 billion in MTEP16. With the increased portfolio cost estimates and increased gas prices and wind energy from MTEP15, MVP Portfolio benefit-to-cost ratios remain comparable to the original business case studied in MTEP11.

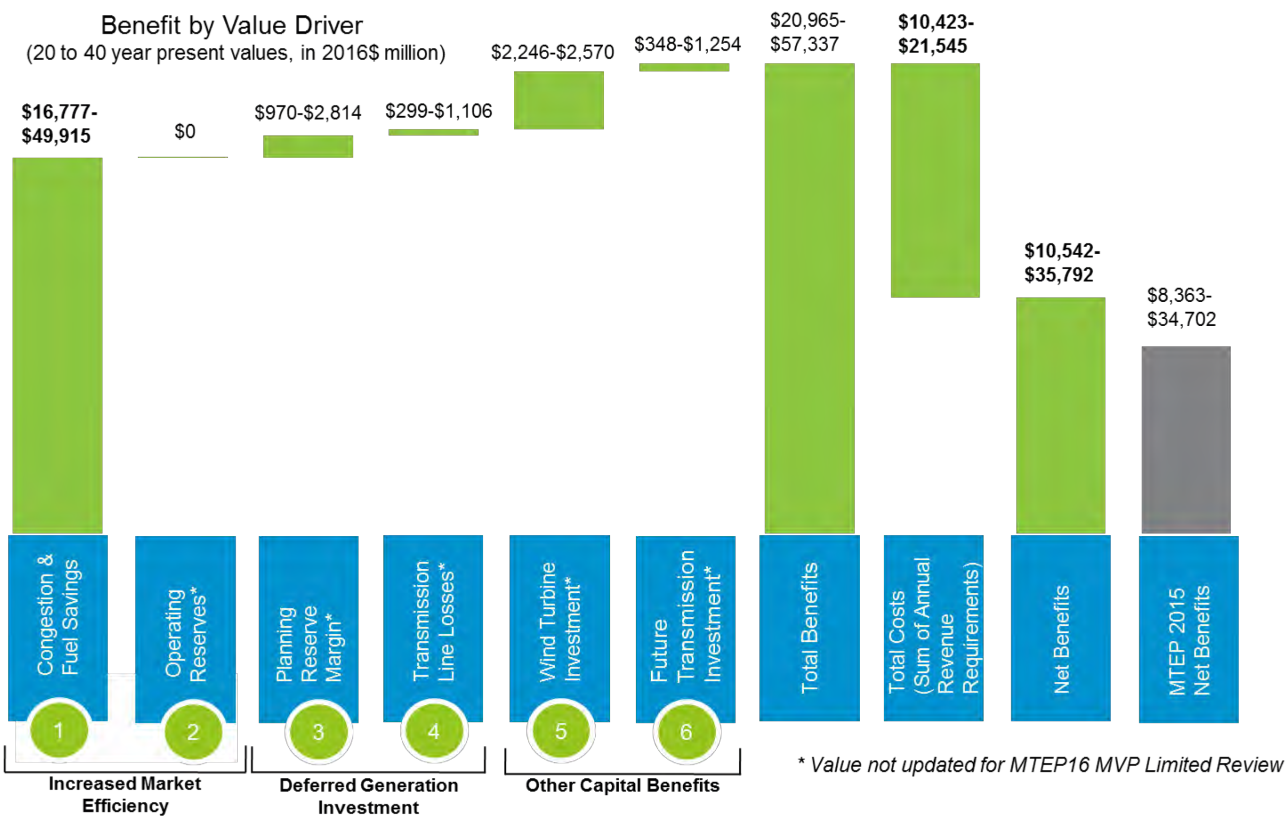


Figure 7.2-1: MVP portfolio economic benefits from MTEP16 MVP Limited Review with values from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP16 compared to MTEP15 and wind energy increase due to the new wind in the model for MTEP16. In addition, the MTEP17 natural gas assumptions, which will be used in the MTEP17 MVP Portfolio Triennial Review, were studied and are comparable to the MTEP16 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table 7.2-1).

[49] Benefits 2 through 6 are from the MTEP14 MVP Triennial Review. The next MVP Triennial Review will occur with MTEP17.

Natural Gas Forecast Assumption	Total Net Present Value Portfolio Benefits ($M-2015)	Total Portfolio Benefit-to-Cost Ratio
MTEP16 – MVP Limited Review	$20,965 – $57,337	2.0 – 2.7
MTEP15 – MVP Limited Review	$19,998 – $55,585	1.9 – 2.6
MTEP17	$19,205 – $52,868	1.8 – 2.5

Table 7.2-1: MVP Portfolio Economic Benefits and Natural Gas Price Sensitivities[50]

Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $17 to $50 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions — an increase of up to 21 percent from the MTEP14 net present value.

An increase in the natural gas price escalation rate and addition of new wind in the model increases congestion and fuel savings benefits by approximately 17 percent in MTEP16 compared to MTEP15

The increase in congestion and fuel savings benefits relative to MTEP15 is primarily due to an increase in the out-year natural gas price forecast assumptions and wind energy increase (Figure 7.2-2). The increased escalation rate causes the assumed natural gas price to be higher in MTEP16 compared to MTEP15 in years 2025 and 2030 — the two years from which the congestion and fuel savings results are based.

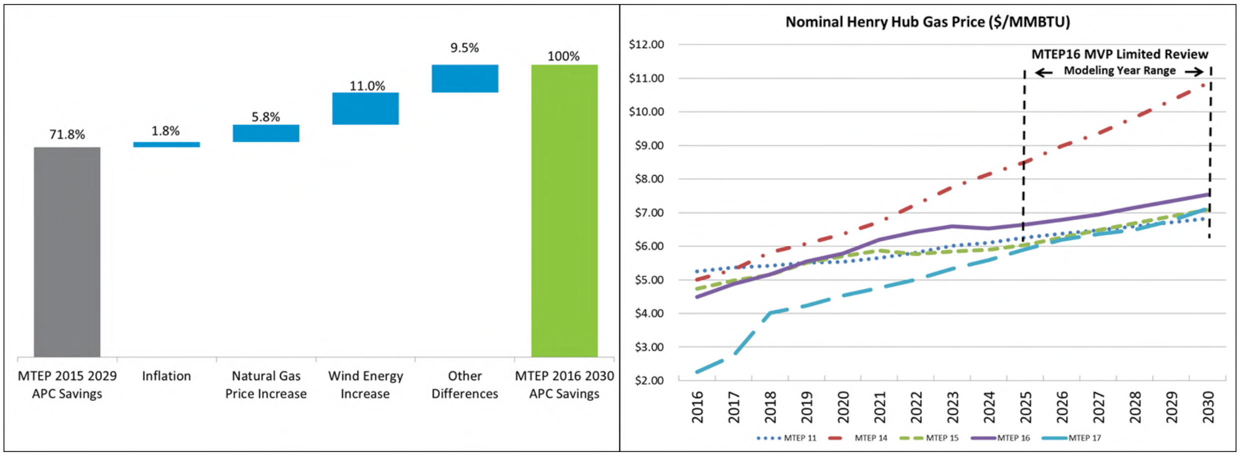


Figure 7.2-2: Breakdown of congestion and fuel savings increase from MTEP15 to MTEP16

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP15 Business as Usual

[50] Sensitivity performed applying MTEP15 and MTEP17 natural gas prices to the MTEP16 congestion and fuel savings model.

(BAU) gas prices assumption to the MTEP16 MVP Limited Review model showed a 6 percent decrease in the annual year 2030 MTEP16 congestion and fuel savings benefits (Figure 7.2-2).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those in the original business case of MTEP11. A sensitivity applying the MTEP17 BAU natural gas prices to the MTEP16 analysis shows just a slight decrease in year 2030 MTEP16 adjusted production cost savings.

The MVP Portfolio is solely located in the MISO North and Central regions and therefore, the inclusion of the MISO South Region to the MISO dispatch pool have little effect on MVP-related production cost savings.

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each local resource zone (Figure 7.2-3). The MVP Portfolio's benefits are at least 1.6 to 2.0 times the cost allocated to each zone.

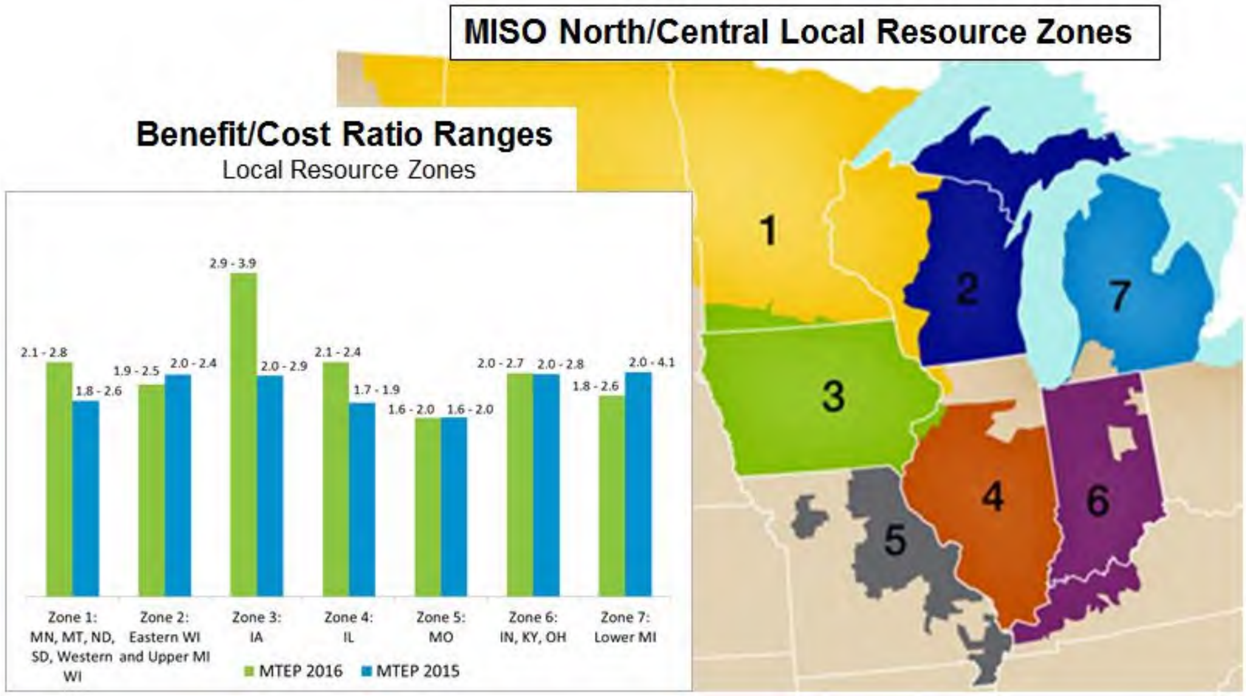


Figure 7.2-3: MVP portfolio total benefit distribution

Going Forward

MTEP16 will feature the full Triennial Review of the MVP Portfolio benefits. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical data.

Chapter 8

Interregional Studies

2016

8.1 PJM Interregional Study

As in 2015, MISO and PJM Interconnection, a Pennsylvania-based regional transmission operator (RTO) that shares borders with MISO, agreed to focus their 2016 joint study efforts on targeted area studies, a targeted Market-to-Market congestion study, FERC Order compliance, and continuation of the interregional process enhancement review in the Interregional Planning Stakeholder Advisory Committee (IPSAC). PJM performs a similar report to MTEP, which it calls the Regional Transmission Expansion Plan (RTEP).

Targeted Area Studies

Continuing on the 2015 Quick Hits work (detailed in the MTEP15 Report), MISO and PJM completed two smaller, targeted area studies in early 2016 that address seams issues. One was in Southwest Michigan and Northern Indiana; the other was in the Quad Cities area of Iowa and Illinois.

In the Michigan/Indiana area, MISO and PJM proposed to evaluate the MTEP and RTEP projects to determine whether the historical congestion, seen in the Quick Hits analysis, would be fully mitigated. This analysis also evaluated the effect of expected operational reconfigurations on the performance of planned projects and whether additional solutions were needed.

MISO and PJM coordinated assumptions to benchmark production cost models to reflect the historical conditions causing issues in the Southwest Michigan and Northern Indiana area. Upon analysis, the production cost models showed little to no future congestion in Southwest Michigan. Sensitivity analyses showed the two major drivers for the reduction in congestion were significant reductions in Michigan imports and the addition of Segreto station interconnection facilities related to the Covert generator moving from the MISO to PJM market. The heavy Michigan imports are not expected to return. The production cost analysis showed similar Northern Indiana congestion as the Quick Hits, primarily on 138 kV facilities. MISO and PJM decided not to pursue project solutions in this area due to the recent Bosserman substation addition and reassessment of flows in the area.

The Quad Cities study was reliability driven to determine if there were projects to supplement or replace three MTEP Appendix B projects (P8842-4) on the Iowa and Illinois border. MISO and PJM built a joint 2020 summer peak powerflow model for analysis. The flows in the joint model were lower than the MTEP14 and MTEP15 models where the reliability drivers had been identified. The joint model was then redispatched to more closely approximate operations.

Contingency analysis on the updated model showed no constraints in the Quad Cities area. MISO and PJM therefore did not pursue interregional solutions to displace or supplement the existing MTEP Appendix B projects. However, the joint model building will help inform the regional process on better MISO-PJM interchange modeling.

Targeted Market-to-Market Congestion Study

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

For the 2016 study, MISO and PJM analyzed historically congested market-to-market flowgates. Flowgates with significant congestion — day-ahead plus excess congestion fund — in 2015 were considered initially. MISO and PJM worked to identify valuable projects on the seam. A valuable project would relieve known market-to-market issues; be completed in a relatively short time frame; have a quick payback on investment; and not be a greenfield project. MISO and PJM coordinated with facility owners to identify the limiting equipment and potential upgrades. Limited reliability and production cost analyses were used to confirm the projects' effectiveness in relieving congestion. Potential projects are expected to be recommended to the MTEP and PJM's RTEP by year's end or Q1 2017, pending the filing of the new Targeted Market Efficiency Project (TMEP) type (discussed in the IPSAC section).

As of November 15, 2016, MISO and PJM have narrowed down the potential upgrades (Table 8.1-1). Due to confidentiality concerns, the specific upgrade details will be shared with stakeholders after MISO/PJM board approval. The Market-to-Market flowgates are identified with preliminary project cost, expected project benefits, and RTO cost share. These are preliminary results and may be subject to change before final project recommendation.

Facility	Transmission Owner(s)	TMEP Cost	TMEP Benefit	Benefit Allocation (%PJM/%MISO)
Burnham – Munster 345 kV	CE, NIPS	$7,000,000	$32,000,000	88/12
Bayshore – Monroe 345 kV	ATSI, ITC	$1,000,000	$17,000,000	89/11
Michigan City – Bosserman 138kV	NIPS, AEP	$4,600,000	$29,600,000	90/10
Reynolds – Magnetation 138 kV	NIPS	$150,000	$14,500,000	41/59
Roxana – Praxair 138 kV	NIPS	$4,500,000	$6,500,000	24/76
Marysville – Tangy 345 kV	AEP, ATSI	TBD	$12,000,000	98/2

Table 8.1-1: MISO-PJM Market Efficiency Projects

FERC Order 1000

FERC issued an Order on Rehearing and Compliance on April 5, 2016, for MISO and PJM's Order 1000 interregional docket. After a 30-day response window and 45-day extension, MISO and its filing partners submitted a compliance filing on June 20, 2016. The compliance filing addressed all six directives from the April 5 Order. Notably, MISO and PJM were directed to add Cross Border Baseline Reliability Projects back into the Joint Operating Agreement (JOA) in addition to the Interregional Reliability Project type. Also, FERC directed the RTOs to consider all projects in the regional transmission plan for Interregional Reliability Project or Interregional Public Policy Project displacement.

The MISO Transmission Owners filed a request for rehearing of the April 5 Order. PJM and their Transmission Owners have filed a request for clarification on the April 5 Order. As of the publishing date, FERC has yet to rule on these motions.

FERC Order EL13-88

Following an initial September 11, 2013, "206" complaint by Northern Indiana Public Service Co. (NIPSCO) on how MISO and PJM perform interregional transmission planning, and subsequent June 15, 2015, FERC technical conference, FERC issued an Order on Complaint and Technical Conference in Docket EL13-88 (NIPSCO Order) on April 21, 2016. MISO and its filing partners submitted the first five directives and one status update from the NIPSCO Order on June 20, 2016.

Those directives included:

- Formalize the steps and deadlines of the Coordinated System Plan study in the JOA
- Lower the Interregional Market Efficiency Project (IMEP) thresholds: MISO made changes to Attachment FF to allow IMEPs above 100 kV and no-cost threshold to qualify as MISO Market Efficiency Projects (MEP)
- Remove the interregional benefit-to-cost ratio
- Revise the benefit calculation of IMEPs: FERC directed the RTOs to use their regional benefit metrics to determine their share of project benefits and, thus, interregional cost allocation
- Include existing business practice manual language on generation interconnection coordination procedures in the JOA

MISO and PJM jointly submitted an informational filing and one status update from the NIPSCO Order on August 19, 2016. This informational filing explored whether and how the RTOs could implement a common timeline between the interregional and regional transmission expansion plans.

MISO and PJM are expecting timely filings of the following outstanding directives:

- Informational filing: How could a joint model be implemented between the RTOs' regional processes? Due October 18, 2016.
- Include generation retirement coordination procedures in the JOA. Due December 15, 2016.

Numerous requests for clarification and/or rehearing were requested from FERC on this docket, including how the benefit calculation of IMEPs will determine the RTOs' cost allocation. FERC will address these in a subsequent order.

IPSAC

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

MISO and PJM presented a new interregional project type in draft redlines of the JOA at the March 7 IPSAC. The new project type, Targeted Market Efficiency Project, gives more definition around the benefits and approval of projects found in the Targeted Market-to-Market Congestion or Targeted Area interregional studies. In the proposal, projects approved as Targeted Market Efficiency Projects by the Joint RTO Planning Committee (JRPC) would go directly to the RTOs' Boards for approval, obviating the need for separate regional analyses. MISO and PJM are still developing the benefit calculations for the new project type and are expecting to file JOA changes with FERC in the fourth quarter of 2016.

Consistent with finding and removing undue hurdles, MISO and PJM proposed two JOA changes in the IPSAC. The first was the removal of the $20 million interregional cost threshold on Cross-Border Market Efficiency Projects. This elimination was filed in December 2015 and accepted by FERC in February 2016.

The second was a proposal to remedy the three approvals needed for interregional projects. The RTOs had suggested that the 1.25 benefit-to-cost ratio threshold in the interregional analysis be replaced with a screening process. The interregional process would still determine the RTO split of benefits and filter potential interregional projects to pass to the regional processes for regional benefit calculation and approval. This proposal by MISO and PJM was superseded by FERC's directive to remove the 1.25 interregional benefit-to-cost ratio in the NIPSCO Order.

8.2 Southwest Power Pool Interregional Coordination

MISO and Arkansas-based Southwest Power Pool (SPP) formally initiated a Coordinated System Plan (CSP) study on May 31, 2016, when the Joint Planning Committee voted in favor of performing a 2016 CSP Study. For the study, MISO and SPP will jointly evaluate seams transmission issues and identify transmission solutions that efficiently address the identified issues to mutual benefit.

The Joint Planning Committee based its decision upon the recommendation of the SPP and MISO portions of the Interregional Planning Stakeholder Advisory Committee[51] (IPSAC), which both voted to commence a joint study in 2016.

While the MISO-SPP Joint Operating Agreement allows up to 18 months to complete the study, MISO and SPP staff committed to a completion date of the first quarter in 2017. This timeline allows the opportunity to initiate another CSP beginning in 2017. The scope for the CSP was reviewed by the IPSAC and approved by SPP-MISO Joint Planning Committee.

Study Purpose And Scope

The MISO-SPP CSP study will consist of an economic evaluation and reliability assessment of seams transmission issues previously identified in MISO and SPP regional planning processes. This will be accomplished by leveraging transmission needs identified in the MTEP16 process and the SPP Integrated Transmission Planning (ITP) studies (2017 ITP10). This will determine if interregional transmission solutions exist that are more efficient and cost-effective than what each RTO could do regionally.

Additionally, MISO's and SPP's generation portfolios are changing in response to increased environmental regulations and economic factors. The RTOs' respective resource mixes are forecasted to change even more rapidly over the next 10 to 20 years. The Midwestern U.S. is witnessing the retirement of a large amount of the conventional generation fleet. Thus, MISO and SPP have the opportunity to optimize the remaining resources while accommodating new resources that can meet electricity demands in compliance with state and federal public policies.

To optimize the new generation and transmission needs in the most cost-effective way, MISO and SPP should seize the opportunity to invest efforts in actionable long-term joint planning that encompasses the changes that are occurring in the electric industry. The 2016 CSP study will serve as a foundational study to inform a broader, longer-term joint and coordinated study effort beginning in 2017.

Consistent with FERC Order No. 1000, the longer-term study should ultimately facilitate the review, approval and ultimate construction of the most efficient or cost-effective transmission solutions to satisfy the needs of both MISO and SPP to relieve congestion, account for public policy considerations, and address reliability issues. Parallel with this 2016 CSP study, MISO and SPP will develop a longer-term study scope to develop a transmission expansion overlay plan that addresses these emerging issues.

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

MISO and SPP will also consider if solutions identified in the 2016 CSP study are beneficial in the short-term and need to be approved prior to the completion of the longer-term study.

The Joint Planning Committee, through the IPSAC, will provide stakeholders an open and transparent forum to provide input and review results during the 2016 MISO-SPP CSP study.

Drivers

The FERC-approved MISO-SPP Joint Operating Agreement requires that the regions, in a non-CSP year, meet and determine whether a joint transmission study should be performed. The IPSAC met on March 9, 2016, for the annual issues review meeting. At this meeting, stakeholders provided feedback on issues they would like to see evaluated in a potential 2016 MISO-SPP CSP. A broad range of issues were proposed including:

- EPA Clean Power Plan (CPP) Impacts
- Settlement Transfer Limits and Contract Path
- Market-to-Market (M2M) Flowgate Congestion
- Interregional Criteria and Benefits,
- Congestion
- Integrated System (IS) Seam

The Joint Planning Committee considered the feedback provided by the IPSAC, as well as a targeted completion date and resource availability, when developing the 2016 MISO-SPP CSP scope.

FERC Order 1000

MISO and SPP received an Order from FERC related to the August 18, 2015, compliance filing on February 2, 2016. MISO and SPP complied with nine out of the 11 directives. However, that Order required MISO and SPP to submit further compliance on two minor issues. On March 1, 2016, MISO and SPP submitted further compliance addressing the two minor issues, which was accepted by FERC on April 6, 2016. With FERC's acceptance, Docket No. ER13-1938 was concluded.

8.3 MISO/ERCOT Study

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

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

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

In 2015 and 2016, MISO and ERCOT successfully established data exchange and communication protocols, which laid a foundation for further collaboration. In addition, MISO and ERCOT planning teams have met in person to better understand each other's planning process.

8.4 Southeastern Regional Transmission Planning

The Southeastern Regional Transmission Planning (SERTP) Region consists of the following FERC-jurisdictional sponsors:

- Duke Energy (Duke Energy Carolinas LLC and Duke Energy Progress Inc.)
- Louisville Gas and Electric Co. and Kentucky Utilities Co. (LG&E/KU)
- Ohio Valley Electric Corp. (OVEC), including its wholly owned subsidiary Indiana-Kentucky Electric Corp.
- Southern Co. Services Inc. (Southern)
- Dalton Utilities
- Georgia Transmission Corp. (GTC)
- Municipal Electric Authority of Georgia (MEAG)
- PowerSouth
- Associated Electric Cooperative Inc. (AECI)
- Tennessee Valley Authority (TVA)

Throughout 2016, MISO and SERTP received final acceptance from FERC on the MISO-SERTP Order 1000 interregional transmission planning compliance filing. MISO and SERTP also continued interregional coordination and data exchange in 2016. Section X of MISO's Attachment FF describes the coordination procedures for interregional transmission coordination with SERTP.

FERC Order 1000

On March 22, 2016, FERC accepted the MISO-SERTP FERC Order 1000 interregional transmission planning compliance filing. This concluded Docket No. ER13-1923 and no further compliance was required.

Interregional Coordination

MISO and SERTP have tariff requirements requiring interregional transmission coordination as described in Section X of Attachment FF of MISO's Tariff. This includes at least one meeting per year to facilitate interregional coordination procedures.

MISO and the SERTP exchange their most current regional transmission plans on an annual basis. This exchange includes powerflow models and associated data used in the regional transmission planning processes.

At least biennially, MISO and the SERTP meet to review the respective regional transmission plans. Such plans include each region's transmission needs as prescribed by each region's planning process. MISO and the SERTP sponsors met on April 7, 2016, at the MISO offices in Metairie, La., to discuss each other's regional transmission plans and to determine if there may be interregional transmission projects that are more cost-effective or efficient than regional projects. If, through this review, MISO and SERTP identify a potential interregional transmission project that may be more efficient or cost-effective than regional transmission projects, the Transmission Provider and the SERTP will jointly evaluate the potential interregional transmission project pursuant to Section X.C.4 of Attachment FF of MISO's Tariff.

Book 4
Regional Energy Information
2016

Chapter 9

Regional Energy Information

2016

9.1 MISO Overview

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

By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $39 to $57 a year, at an annual expense of $5 per customer

MISO has 52 Transmission Owner members with more than $31.4 billion in transmission assets under MISO's functional control. MISO has 123 non-transmission owner members that contribute to the stability of the MISO markets.

The services MISO provides translate into material benefits for members and end users. By improving grid reliability and increasing the efficient use of generation, MISO saves the average residential customer $39 to $57 a year at an annual expense of $5 per customer. The MISO 2015 Value Proposition[52] explains the various components of this benefits calculation.

The value drivers are:

1. **Improved Reliability** - MISO's broad regional view and state-of-the-art reliability tool set enables improved reliability for the region as measured by transmission system availability.
2. **Dispatch of Energy** - MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.
3. **Regulation** - With MISO's Regulation Market, the amount of regulation required within the MISO footprint dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets.
4. **Spinning Reserves** - Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement declined, freeing low-cost capacity to meet energy requirements.
5. **Wind Integration** - MISO's regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.
6. **Compliance** - Before MISO, utilities in the MISO footprint managed their own FERC and NERC compliance. With MISO, many of these compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.
7. **Footprint Diversity** - MISO's large footprint increases the load diversity allowing for a decrease in regional planning reserve margins from 18.8 percent to 15.2 percent. This decrease delays the need to construct new capacity.
8. **Generator Availability Improvement** - MISO's wholesale power market improved power plant availability by 1.5 percent, delaying the need to construct new capacity.
9. **Demand Response** - MISO enables demand response through transparent market prices and market platforms. MISO-enabled demand response delays the need to construct new capacity.

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

10. **MISO Cost Structure** - MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

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

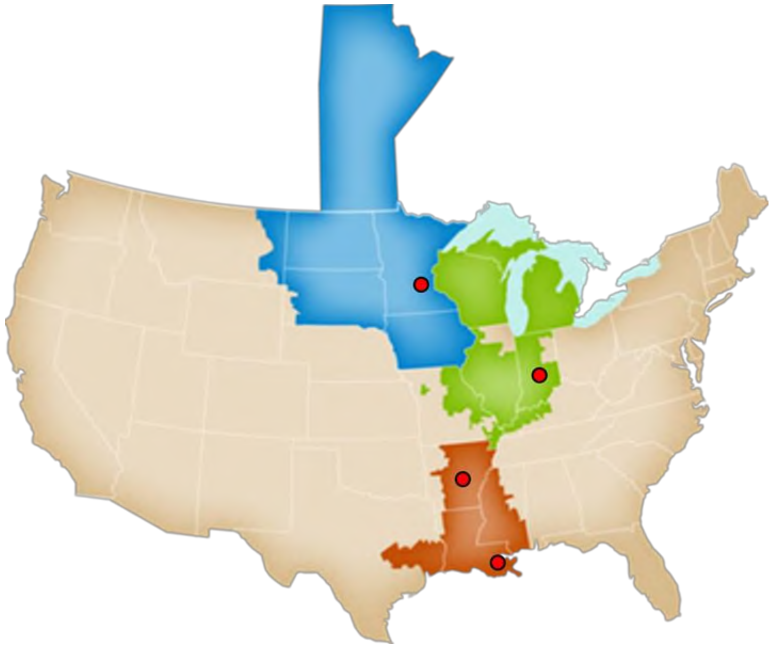


Figure 9.1-1: The MISO geographic footprint and office locations

MISO By The Numbers

Generation Capacity (as of September 2016)

- 176,559 MW (market)
- 191,985 MW (reliability)[53]

Historic Summer Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 130,917 MW (reliability)[54]

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

- 109,307 MW (market)
- 117,629 MW (reliability)[55]

Miles of transmission

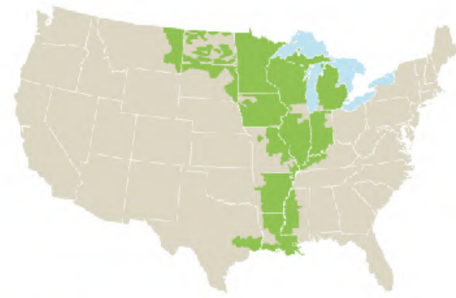
- 65,800 miles of transmission
- 8,400 miles of new/upgraded lines planned through 2023

Markets

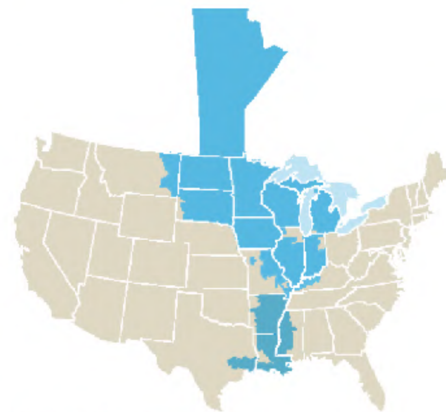
- $24.7 billion in annual gross market charges (2015)
- 2,545 pricing nodes
- 426 Market Participants serving more than 42 million people

Renewable Integration

- 15,215 MW active projects in the interconnection queue
- 14,995 MW wind in service
- 16,268 MW registered wind capacity
- 13,088 MW Historic Wind Peak (set Feb. 19, 2016)



Market Area



Reliability Coordination Area

[53,3,4] MISO Fact Sheet

9.2 Electricity Prices

Wholesale Electric Rates

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

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

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

The 24-hour average day-ahead LMP at the Indiana hub over a two-week period highlights the variation in the components that make up the LMP for the first two weeks in 2016 (Figure 9.2-1). A real-time look at the MISO prices can be found on the LMP Contour Map[56] (Figure 9.2-2).

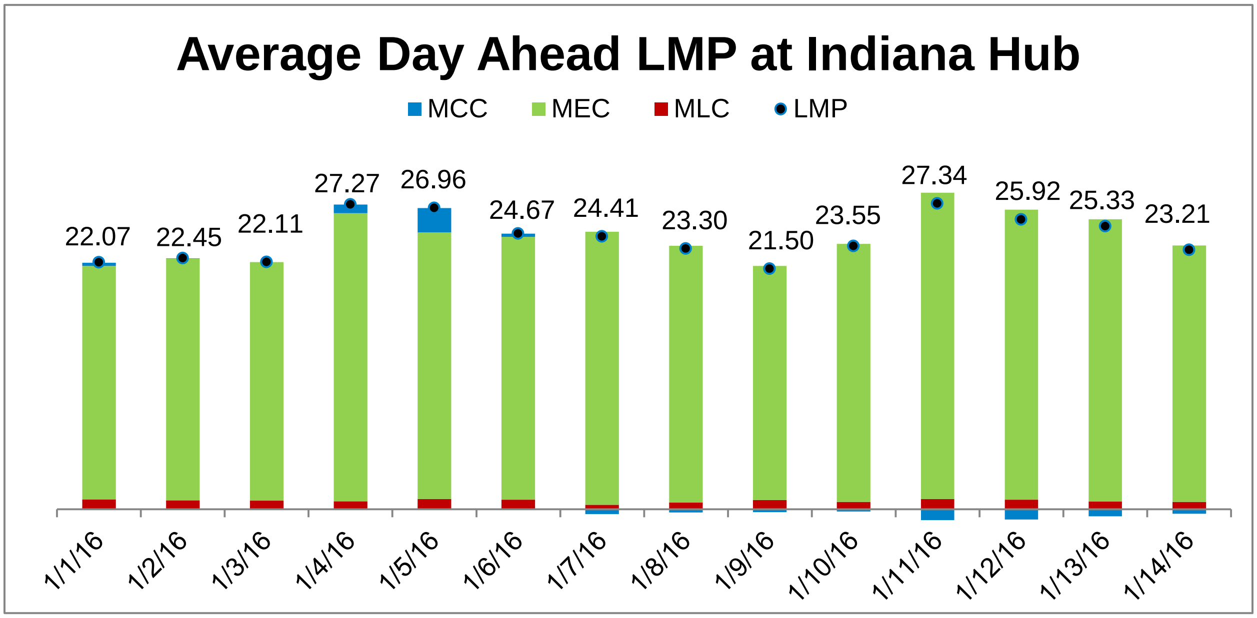


Figure 9.2-1: Average day-ahead LMP at the Indiana hub

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

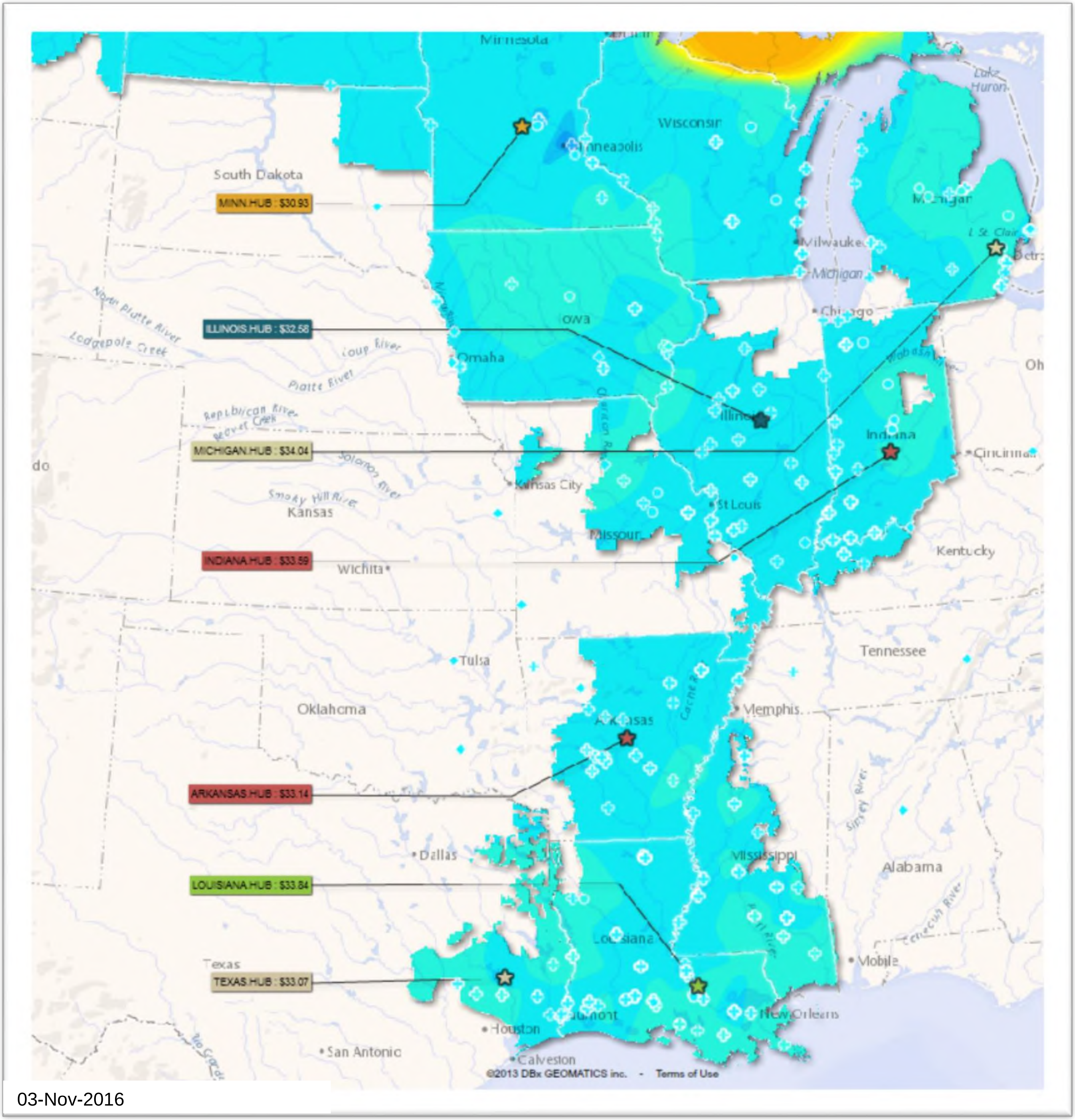


Figure 9.2-2: LMP contour map

Retail Electric Rates

The MISO-wide average retail rate, weighted by load in each state, for the residential, commercial and industrial sector, is 8.74 cents/kWh, about 14 percent lower than the national average of 9.99 cents/kWh. The average retail rate in cents per kWh varies by 3.9 cents/kWh per state in the MISO footprint (Figure 9.2-3).

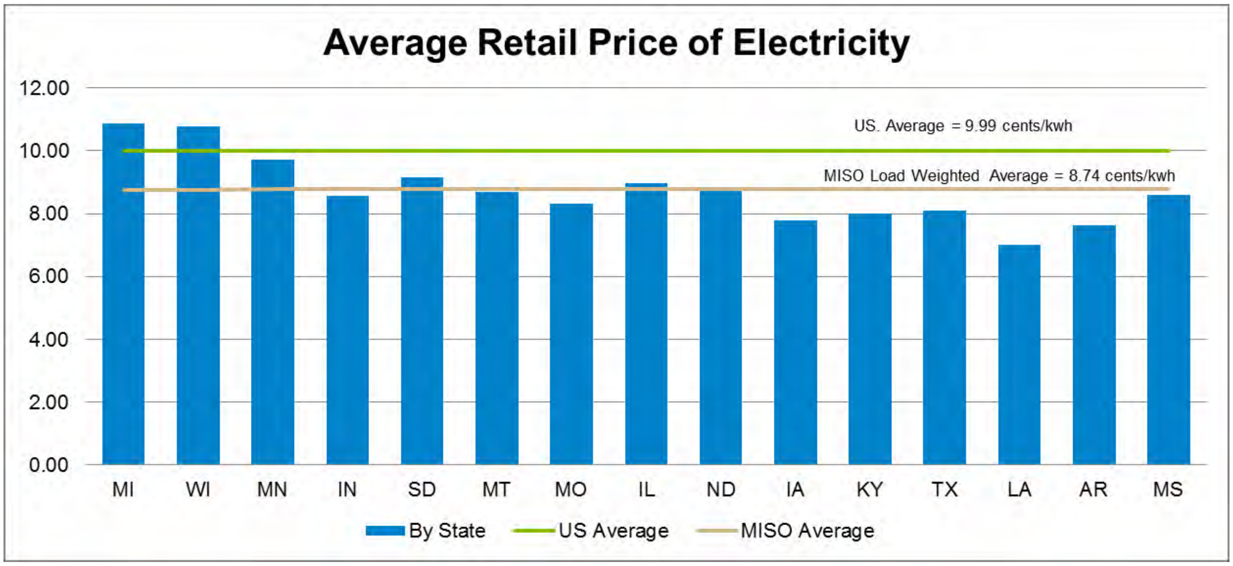


Figure 9.2-3: Average retail price of electricity per state[57]

[57] May 2014 EIA Electric Power Monthly with Load Ratio Share data calculated from December 2013 MISO Attachment O data

9.3 Generation

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

Fuel availability and fuel prices introduce a regional aspect into the selection of generation, not only in the past but also going forward. Planned generation additions and retirements in the U.S. from 2015 to 2019, separated by fuel type, shows the increased role natural gas and renewable energy sources will play in the future (Table 9.3-1).

	Planned Generating Capacity Changes, by Energy Source, 2015-2019					
	Generator Additions		Generator Retirements		Net Capacity Additions	
Energy Source	**Number of Generators**	**Net Summer Capacity (MW)**	**Number of Generators**	**Net Summer Capacity (MW)**	**Number of Generators**	**Net Summer Capacity (MW)**
Coal	6	694	178	28,892	-173	-28,198
Petroleum	31	59	72	1,622	-41	-1,563
Natural Gas	389	54,893	131	7,887	258	47,006
Other Gases	3	403	--	--	3	403
Nuclear	3	3,322	1	610	2	2,712
Hydroelectric Conventional	66	1,088	22	433	44	655
Wind	198	21,624	6	60	192	21,564
Solar Thermal and Photovoltaic	627	13,220	1	1	626	13,219
Wood and Wood-Derived Fuels	5	199	6	37	-1	162.7
Geothermal	8	192	--	--	8	191.8
Other Biomass	57	263	32	52	25	211
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	20	579	2	1	18	578
U.S. Total	**1,412**	**96,536**	**451**	**39,594**	**961**	**56,942**

Table 9.3-1: Forecasted generation capacity changes by energy source[58]

The majority of MISO North and Central regions' dispatched generation comes, historically, from coal. With the introduction of the South region, MISO added an area where a majority of the dispatched generation comes from natural gas. The increased fuel-mix diversity from the addition of the South region helps to limit the exposure to the variability of fuel prices. This adjustment

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

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

to the composition of resources contributes to MISO's goal of an economically efficient wholesale market that minimizes the cost to deliver electricity.

After the December 2013 integration of the South region, the percentage of generation from coal units decreases as the amount of generation from gas units increases as shown by trend lines (Figure 9.3-1).

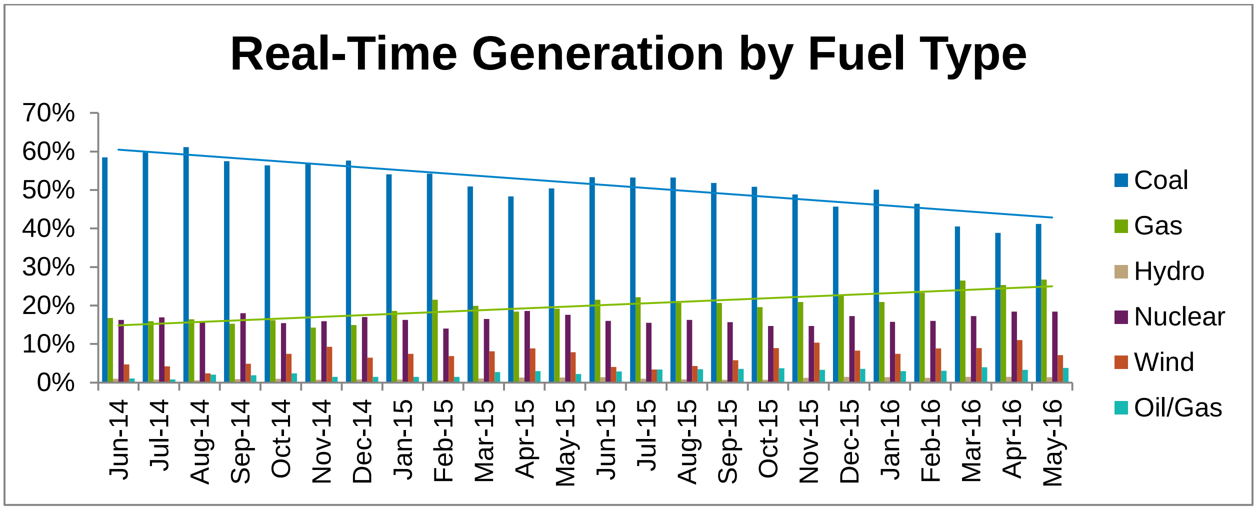
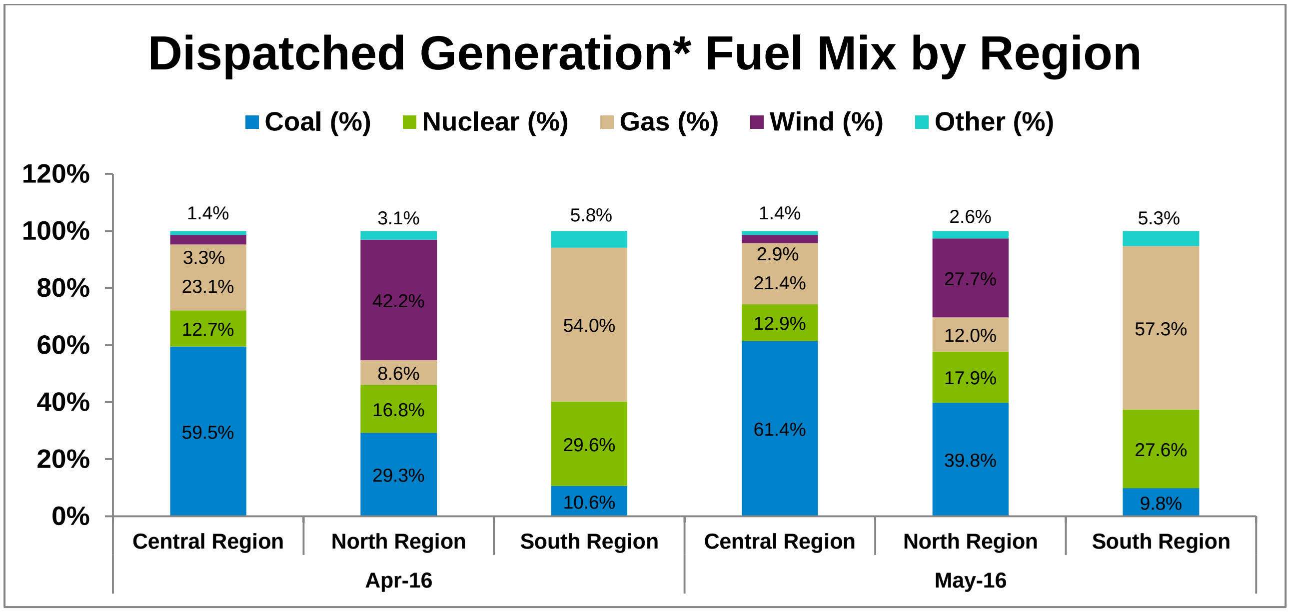


Figure 9.3-1: Real-time generation by fuel type

Different regions have different makeups in terms of generation (Figure 9.3-2). A real-time look at MISO fuel mix can be found on the [MISO Fuel Mix Chart.](https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/FuelMix.aspx)[59]



* Based on 5-minute unit level dispatch target

Figure 9.3-2: Dispatched generation fuel mix by region

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

Renewable Portfolio Standards

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

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

State	RPS Type	Target RPS (%)	Target Mandate (MW)	Target Year
Arkansas	None			
Iowa	Standard		105	1999
Illinois	Standard	25%		2025
Indiana	Goal	10%		2025
Kentucky	None			
Louisiana	None			
Michigan	Standard	10%	1,100	2015
Minnesota	Standard: all utilities	25%		2025
	Xcel Energy	30%		2020
	Solar standard – investor-owned utilities	1.5%		2020
Missouri	Standard	15%		2021
Mississippi	None			
Montana	Standard	15%		2015
North Dakota	Goal	10%		2015
South Dakota	Goal	10%		2015
Texas	Standard		5,880	2015
Wisconsin	Standard	10%		2015

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

Wind

Wind energy is the most prevalent renewable energy resource in the MISO footprint. Wind capacity in the MISO footprint has increased exponentially since the start of the energy market in 2005. Beginning with nearly 1,000 MW of installed wind, the MISO footprint now contains 15,106 MW of total registered wind capacity as of May 2016.

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

A real-time look at the average wind generation in the MISO footprint can be seen on the MISO real time wind generation graph[60].

Data collected from the MISO Monthly Market Assessment Reports[61] determines the energy contribution from wind and the percentage of total energy supplied by wind (Figure 9.3-3).

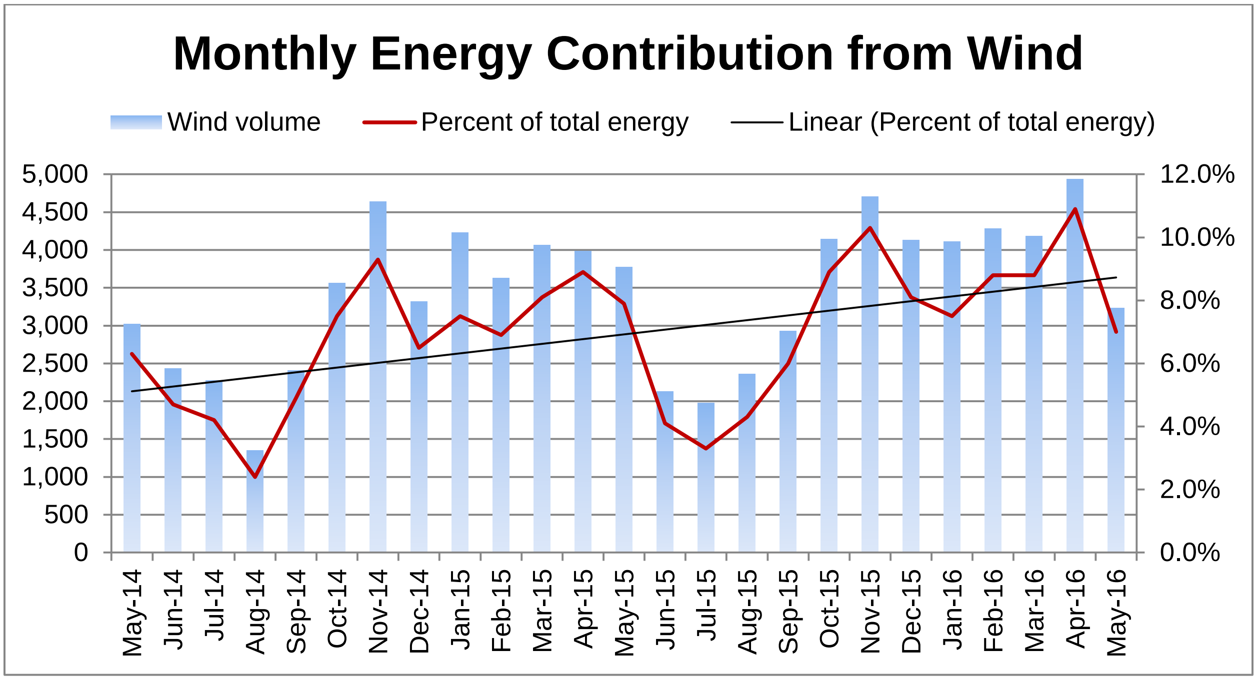


Figure 9.3-3: Monthly energy contribution from wind

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

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

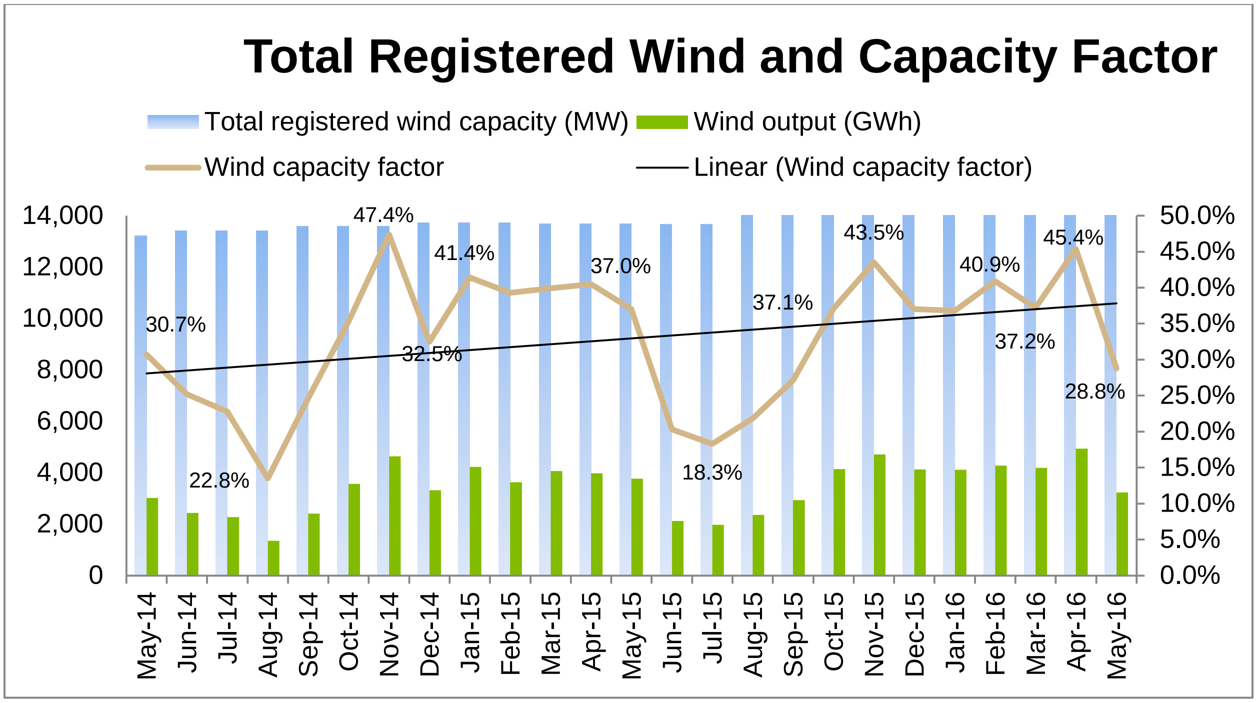


Figure 9.3-4: Total registered wind and capacity factor

9.4 Load Statistics

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

In 2014, with the addition of the South region, MISO set a new all-time winter instantaneous peak load of 109.3 GW on January 6. The new peak surpassed the previous all-time winter peak of 99.6 GW set in 2010.

End-Use Load

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

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

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

April 2016 - Retail Sales of Electricity to Ultimate Customers by End-Use Customer							
State	Residential		Commercial		Industrial		All Sectors
	(Million kWh)	% of total	(Million kWh)	% of total	(Million kWh)	% of total	
Arkansas	1,041	32.6%	877	27.4%	1,278	40.0%	3,195
Iowa	920	26.0%	895	25.3%	1,728	48.8%	3,543
Illinois	2,812	28.1%	3,828	38.3%	3,327	33.3%	10,004
Indiana	1,999	28.3%	1,764	25.0%	3,298	46.7%	7,063
Kentucky	1,610	30.5%	1,416	26.8%	2,250	42.6%	5,276
Louisiana	1,762	27.4%	1,823	28.4%	2,840	44.2%	6,426
Michigan	2,305	29.7%	2,969	38.2%	2,499	32.1%	7,774
Minnesota	1,485	31.2%	1,750	36.8%	1,525	32.0%	4,761
Missouri	1,960	38.3%	2,240	43.8%	914	17.9%	5,116
Mississippi	1,050	30.7%	999	29.2%	1,371	40.1%	3,419
Montana	369	33.5%	382	34.7%	349	31.7%	1,100
North Dakota	348	24.9%	463	33.1%	586	41.9%	1,398
South Dakota	329	36.6%	365	40.6%	206	22.9%	900
Texas	8,354	30.1%	10,575	38.1%	8,847	31.8%	27,790
Wisconsin	1,527	29.4%	1,789	34.5%	1,878	36.2%	5,193
	27,871	30.0%	32,135	34.6%	32,896	35.4%	92,958

Table 9.4-1: Retail sales of electricity to ultimate customers by end-use sector, April 2016[62]

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

Load

Peak load drives the amount of capacity required to maintain a reliable system. Load level variation can be attributed to various factors, including weather, economic conditions, energy efficiency, demand response and membership changes. The annual peaks, summer and winter, from 2007 through 2015, show the fluctuation (Figure 9.4-2).

Within a single year, load varies on a weekly cycle. Weekdays experience higher load. On a seasonal cycle, it also peaks during the summer with a lower peak in the winter, and with low-load periods during the spring and fall seasons (Figure 9.4-3). The Load Curve shows load characteristics over time (Figure 9.4-4). Looking at all 365 days in 2015, these curves show the highest instantaneous peak load of 120,016 MW on July 29, 2015; the minimum load of 51,459 MW on May 3, 2015; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

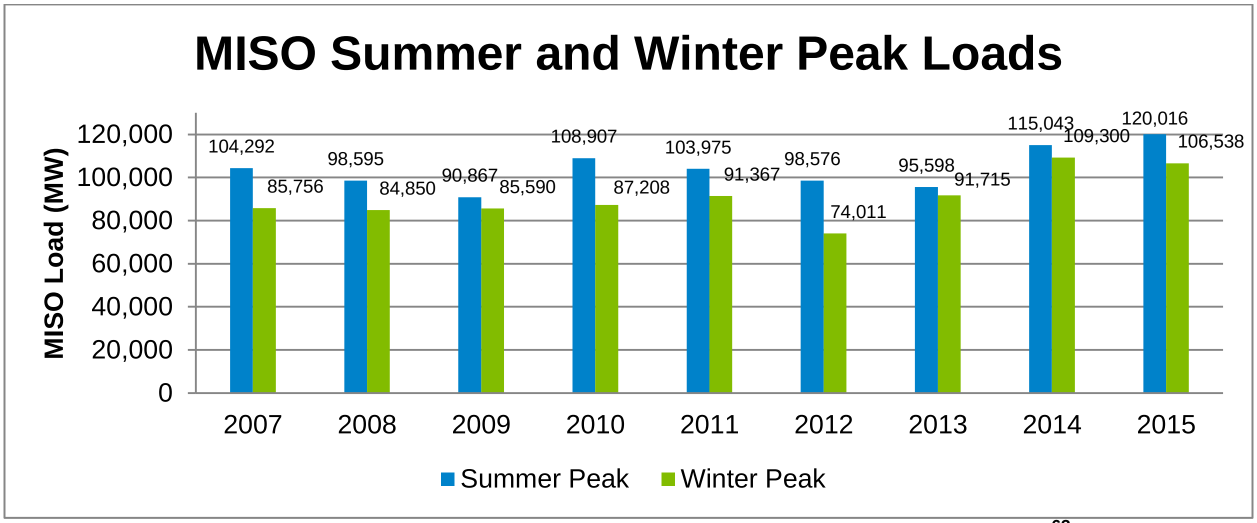


Figure 9.4-2: MISO Summer and Winter Peak Loads – 2007 through 2015[63]

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

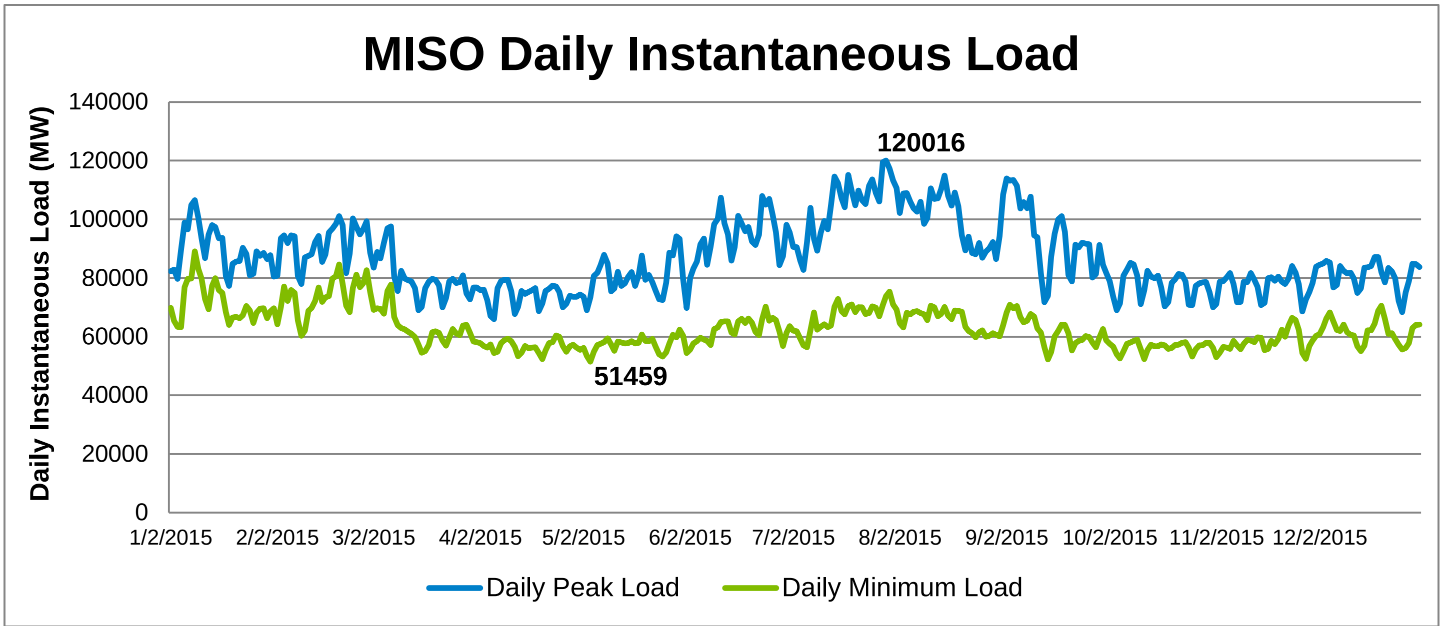


Figure 9.4-3: 2015 MISO - Daily Load[64]

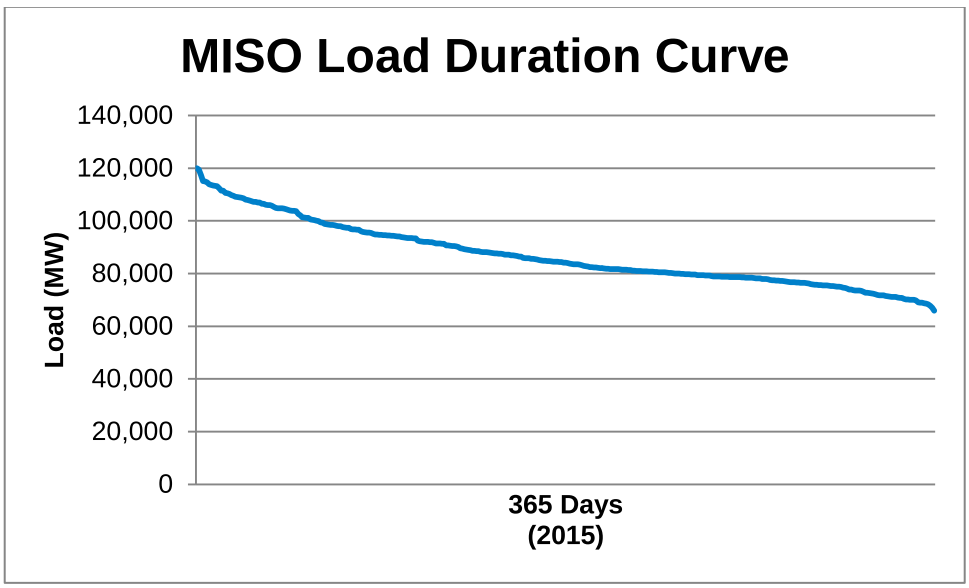


Figure 9.4-4: MISO Load Duration Curve – 2015[65]

[64] Source: MISO Market Data (2014)
[65] Source: MISO Market Data (2014)

Appendices

Most MTEP16 appendices[66] are available and accessible on the MISO public webpage. Confidential appendices, such as D2 - D8, are available on the MISO MTEP16 Planning Portal[67]. Access to the Planning Portal site requires an ID and password.

Appendix A: Projects recommended for approval

A.1, A.2, A.3: Cost allocations
A: MTEP16 Appendix A new projects and existing projects

Appendix B: Projects with documented need and effectiveness

Appendix D: Reliability studies analytical details with mitigation plan[68]

Section D.1: Project justification
Section D.2: Modeling documentation
Section D.3: Steady state
Section D.4: Voltage stability
Section D.5: Transient stability
Section D.6: Generator deliverability
Section D.7: Contingency coverage
Section D.8: Nuclear plant assessment
Section D.9: Planning Horizon Transfers
Section D.10: Short Circuit Analysis

Appendix E: Additional MTEP16 Study support

Section E.1: Reliability planning methodology
Section E.2: Futures development

Appendix F: Stakeholder substantive comments

66 https://www.misoenergy.org/Library/Pages/Results.aspx?q=MTEP16%20Appendix
67 https://markets.midwestiso.org/MTEP/Studies/42/Study
68 Appendix D is available on MISO's FTP site

Acronyms in MTEP16

AECI	Associated Electric Cooperative Inc.
AEG	Applied Energy Group
AFC	Available Flowgate Capacity
AMIL	Ameren Illinois
APC	Adjusted Production Cost
ARR	Auction Revenue Rights
BA	Balancing Authority
BAU	Business as Usual
BaseRel	Baseline Reliability Project
BPM	Business Practices Manual
BRP	Baseline Reliability Projects
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CT	Combustion Turbine
CEII	Critical Energy Infrastructure Information
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CROW	Control Room Operator’s Window
CSP	Coordinated System Plan
CSAPR	Cross-State Air Pollution Rule
DCLM	Direct control load management
DG	Distributed Generation
DPP	Definitive Planning Phase
DR	Demand Response
DSG	Down Stream of Gypsy
DSIRE	Database of State Incentives for Renewables & Efficiency
DSM	Demand-Side Management
EE	Energy Efficiency
EER	Energy Efficiency Resource
EGEAS	Electric Generation Expansion Analysis System
EIA	Energy Information Agency
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency (U.S.)
ERAG	Eastern Reliability Assessment Group
ERC	Emission Rate Credits
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
EER	Energy Efficiency Resources
EERS	Energy Efficiency Resource Standards
FCA	Facility Construction Agreement
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Projects
GIQ	Generator Interconnection Queue
GIS	Geographical Information System
GTC	Georgia Transmission Corp.
GVTC	Generator Verification Test Capacity
HD	High Demand
IL	Interruptible Load
IMEP	Interregional Market Efficiency Project
IPP	Independent Power Producers
IPSAC	Interregional Planning Stakeholder Advisory Committee
IS	Integrated System
ITP	Integrated Transmission Plan
JOA	Joint Operating Agreement
JRPC	Joint RTO Planning Committee
LBA	Local Balancing Authority
LD	low demand
LFU	Load forecast uncertainty
LG&E/KU	Louisville Gas and Electric Co./Kentucky Utilities
LMP	Locational marginal price
LMR	Load Modifying Resources

LOLE Loss of Load Expectation
LOLEWG Loss of Load Expectation Working Group
LRR Local Reliability Requirement
LRZ Local Resource Zones
LSE Load Serving Entity
LTRA Long-Term Resource Assessment
LTTR Long-Term Transmission Rights
M2M Market-To-Market
MATS Mercury and Air Toxics Standard
MCC Marginal Congestion Component
MCPS Market Congestion Planning Studies
MEAG Municipal Electric Authority of Georgia
MEC Marginal Energy Component (MEC)
MECT Module E Capacity Tracking
MEP Market Efficiency Projects
MISO Midcontinent Independent System Operator
MLC Marginal Loss Component
MMWG Multi-regional Modeling Working Group
MOD Model on Demand
MTEP MISO Transmission Expansion Plan
MVP Multi-Value Projects
MW Megawatt
NAAQS National Ambient Air Quality Standards
NERC North American Electric Reliability Corp.
NIPSCO Northern Indiana Public Service Co.
NO_x Nitrogen Oxide
NRIS Network Resource Interconnection Service
OASIS Open Access Same-Time Information System
OMS Organization of MISO States
OOS Out of Service
OVEC Ohio Valley Electric Corp.
PAC Planning Advisory Committee
PJM Pennsylvania-New Jersey-Maryland Interconnection
PRA Planning resource auction
PRM Planning Reserve Margin
PRM_{ICAP} PRM installed capacity
PRM_{UCAP} PRM uninstalled capacity
PRMR Planning Reserve Margin Requirement
PSC Planning Subcommittee
PV Photovoltaic
PV Present Value
RCPP Regional Clean Power Plan
RE Regional Entities
RECB Regional Expansion Criteria and Benefits
RFP Request For Proposal
RGOS Regional Generator Outlet Study
RPS Renewable Portfolio Standard
RRF Regional Resource Forecast
RTEP Regional Transmission Expansion Plan
RTO Regional transmission operator
SERTP Southeastern Regional Transmission Planning
SIS System Impact Study
SPC System Planning Committee
SPM Subregional Planning Meetings
SPP Southwest Power Pool
SRCPP Sub-Regional Clean Power Plan
SREC Sub-Regional Export Constraint
SUFG State Utility Forecasting Group
SSR System Support Resource
TDSP Transmission Delivery Service Project
TIS Total Interconnection Service
TMEP Targeted Market Efficiency Project
TO Transmission Owner
TPL Transmission Planning Standards
TSR Transmission Service Request
TSTF Technical Study Task Forces
TVA Tennessee Valley Authority
UNDA Universal Non-disclosure Agreement
VLR Voltage and Local Reliability Study
WOTAB West of the Atchafalaya Basin

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MISO would like to thank the many stakeholders who provided MTEP16 report comments, feedback, and edits. The creation of this report is truly a collaborative effort of the entire MISO region.

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Target Appendix	App AB	Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	State 1	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Min)	Expected ISD (Max)	Max kV	Min kV	Transmission Project Category
A in MTEP16	B>A	Central	AmerenIL	3005	S. Belleville-Tilden Terminal Equipment U	Baldwin 138 kV Substation - Construct a 5 position 138 kV ring bus at Baldwin Substation (5 - 3000 A, 40 kA PCBs). Build a 138 kV double-circuit line between Baldwin Substation and the tap to the South Belleville-Tilden 1526 138 kV line by rebuilding 2 miles of existing single-circuit 138 kV line to double-circuit capability, both circuits to have 2000 A summer emergency capability.	IL	IL	Other		Reliability	$3,400,000	6/1/2017	6/1/2017	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	7820	Hennepin-Kewanee-6101 Reconductoring	Upgrade terminal equipment at Hennepin terminal.	IL	IL	Other		Condition	$300,000	6/1/2017	6/1/2017	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	7860	Effingham 138-Effingham NW Increase G	Effingham 138-Effingham, Northwest 138 kV Line - Elevate 2.72 miles of 954 kcmil ACSR conductor to permit operation at 120 degrees C. Upgrade terminal equipment at Effingham 138 Substation.	IL	IL	BaseRel			$2,000,000	6/1/2016	6/1/2016	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	7869	Alsey Tap (Ballard) Breaker Station	Install 138 kV breaker station near tap to the PPI Alsey Plant on the Jerseysville, Northwest-Meredosia-1 138 kV line. May be an ultimate 6-breaker ring bus.	IL	IL	Other		Reliability	$6,626,495	5/1/2016	5/1/2016	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9261	Searitt Breaker Station	Build a 3-breaker 138 kV ring bus (Searitt Breaker Station) adjacent to the N. Decatur-Latham-1566 138 kV line near the planned Enbridge Pumping Station. Buld a radial 138 kV line to the new customer substation.	IL	IL	Other		Reliability	$4,563,667	6/1/2016	12/1/2017	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9722	Frederick, North 138-69 kV Transformer R	Replace existing 138-69 kV transformer bank with 112 MVA unit.	IL	IL	Other		Distribution		10/3/2016	10/3/2016	138	69	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9726	Fogarty 138-34.5 kV Transformer Connect	Provide 138 kV connection to supply 138-34.5 kV transformer	IL	IL	Other		Distribution	$1,726,448	6/1/2018	6/1/2018	138	34.5	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9727	Wakefield Substation	Establish 138 kV ring bus; connect to South Bloomington-Clinton-1372 line to supply Wakefield Substation	IL	IL	Other		Distribution	$7,430,056	6/1/2019	6/1/2019	138	34.5	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9736	East Quincy-Hamilton-4 Reconductoring	Replace existing conductor	IL	IL	Other		Condition	$8,315,916	5/1/2016	5/1/2016	138	138	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9741	E. Collinsville-Porter Road Terminal Equip	Upgrade terminal equipment at Porter Road	IL	IL	Other		Reliability	$50,000	5/24/2016	5/24/2016	138	138	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9845	Gallatin 138 kV Ring Bus	Construct 138 kV ring bus	IL	IL	Other		Distribution	$5,621,250	5/1/2017	5/1/2017	138	69	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9853	Mt. Vernon, West Terminal Equipment	Upgrade terminal equipment in Prairie State-Mt. Vernon, West position	IL	IL	Other		Condition		6/1/2017	6/1/2017	345	345	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9869	Havana-Springfield 138 kV Upgrade	Upgrade terminal equipment	IL	IL	Other		Condition		6/1/2017	6/1/2017	138	138	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	9873	Edwards 138-69 kV Transformer Addition	Install 138-69 kV Transformer	IL	IL	Other		Distribution		12/1/2016	12/1/2016	138	69	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	10884	Roxford Substation - Replace 345/138 kV	Roxford 345/138 kV Substation - Replace 345/138 kV, 560 MVA transformer with a 700 MVA unit, and install a 3000 A, 50 kA PCB to place the transformer on its own position at Roxford Substation.	IL	IL	BaseRel			$3,611,589	5/23/2016	5/23/2016	345	138	Bottom-up
A in MTEP16	B>A	Central	AmerenIL	10904	Brokaw-Gibson City South-1582 Recondu	Rebuild to 1200 A summer emergency capability. Upgrade line terminal equipment at Gibson City South Substation.	IL	IL	Other		Condition	$10,318,299	12/1/2016	12/1/2016	138		Bottom-up
A in MTEP16	B>A	Central	AmerenIL	11063	Rising-North Champaign-1592 Terminal U	Upgrade terminal equipment at Rising Substation on the Rising-North Champaign-1592 138 kV line position.	IL	IL	Other		Condition	$1,747,553	12/1/2016	12/1/2016	138		Bottom-up
A in MTEP16	B>A	Central	AmerenMO	10483	Cape-Kelso-2 and Kelso-Miner-2 - Increas	Increase ground clearance to and perform line hardware verification to permit operation at 120 degrees C. Upgrade terminal equipment at Cape, Kelso, and Miner Substations.	MO	MO	Other		Condition	$5,586,082	12/1/2016	12/1/2016	161	161	Bottom-up
A in MTEP16	B>A	Central	AmerenMO	10604	Page-Sioux-4 Reconductoring	Replace 14.28 miles of 2-300 kcmil Copper conductor with conductor matching or exceeding the capability of the rest of the line (954 kcmil ACSR conductor)	MO	MO	Other		Condition		12/1/2016	12/1/2016	138		Bottom-up
A in MTEP16	B>A	Central	CWLD	10162	McBaine Line Terminal Upgrades	Upgrade McBaine-McBaine Tap line to 249 MVA (300501 bus). Replace a switch (from 600 A to 1200 A) and a wave trap (from 600 A to 2000 A). Limiting element will be conductor at 895 A = 249 MVA.	MO	MO	Other		Reliability	$50,000	3/1/2016	3/1/2016	161		Bottom-up
A in MTEP16	B>A	Central	DEI	2873	Danville E. 69kV looped feed	Construct new Danville East substation near HRH hospital - single 22.4MVA transformer - 6945 ckt to be looped through	IN	IN	Other		Distribution	$990,000	6/1/2018	6/1/2018	69	12	Bottom-up
A in MTEP16	B>A	Central	DEI	9834	Noblesville to Tipton W. 230kV Rebuild	Noblesville to Tipton West 23008 ckt: Replace all single/H-frame pole structures with steel poles, reconductor with 954ACSR45X7 OVAL / OPGW and build Switching Station with 3-2000A line switches near existing Carmel 146th St. junction.	IN	IN	Other		Condition	$12,079,985	12/31/2018	12/31/2018	230		Bottom-up
A in MTEP16	B>A	Central	DEI	9850	Lebanon Prairie Crk. 69kV Switching Stati	New Lebanon Prairie Crk. 69kV Switching Station to be inserted in the 6983 ckt.	IN	IN	Other		Distribution	$3,518,244	12/31/2017	12/31/2017	69		Bottom-up

Target Appendix	App AB	Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	State 1	State2	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Min)	Expected ISD (Max)	Max kV	Min kV	Transmission Project Category
A in MTEP16	B>A	West	ITCM	10269	Lore-Hickory Creek 161kV Rebuild	Rebuild 6.81 miles of the Lore-Hiclory Creek 161kV line and upgrade the Lore 161kV terminal.	IA	IA	BaseRel			$12,700,847	12/31/2017	12/31/2017	161	161	Bottom-up
A in MTEP16	B>A	West	ITCM	10303	Willaimsburg 161kV Temp Conversion	To provide a reliable conversion to 69kV the 34.5kV will need temporary configurations to provide a reliable transition. The Williamsburg 115kV high side will be converted to 161kV. The two aging and miss-matched 115/34.5kV transformers will be replaced with a newer and larger 161/36kV transformer from the Hiawatha Substation. This will provide an increased level of reliability to Williamsburg by serving the high-side from a newly rebuilt and shorter 161kV line compared to an older and longer 115kV line.	IA	IA	Other		Reliability	$1,204,368	12/30/2017	12/31/2017	161	34	Bottom-up
A in MTEP16	B>A	West	ITCM	11163	Devils Creek	69 kV customer interconnection near Ft. Madison, IA. Build a new Devils Creek 69kV distributions substation.	IA	IA	Other		Distribution	$2,026,223	12/31/2017	12/31/2017	69		Bottom-up
A in MTEP16	B>A	West	ITCM	11164	Oelwein Hub Distribution Sub	ITCM will form an in and out configuration and install two line breakers at the new substation.	IA	IA	Other		Distribution	$6,317,468	4/30/2017	4/30/2017	69		Bottom-up
A in MTEP16	B>A	West	ITCM	11763	J344 Network Upgrades - Irvine Switch St	To provide a point of interconnection for project J344, a 169 MW wind-powered generating facility, a new 3-terminal, 3-breaker "Irvine" ring bus substation on the Poweshiek to Beacon 161 kV line . The Network Upgrade was required to interconnect the project to the transmission system, and the Network Upgrade was required as a condition of Interconnection Service for project J344.	IA	IA	GIP			$5,537,540	9/1/2017	9/1/2017	161	161	Externally-Driven
A in MTEP16	B>A	West	ITCM, XEL	11883	Huntley - Wilmarth 345 kV	Huntley to Wilmarth 345 kV Single Ckt Transmission Line - 38.5 miles	MN	MN	MEP	Shared		$108,000,000	1/1/2022	1/1/2022	345		Top-Down
A in MTEP16	B>A	West	MDU	4140	Bowdle Jct	Build a new Bowdle Jct to replace old Bowdle substation	SD	SD	Other		Reliability	$5,500,000	6/30/2017	6/30/2017	115	41.6	Bottom-up
A in MTEP16	B>A	West	MDU	9120	Leola	A new 115 kV transmission line from the Ellendale Jct. Substation to a new Leola Jct. 115/41.6 Substation. The new Leola Jct. substation will connect to the existing Ellendale-Bowdle 41.6 kV line.	SD,ND	SD	Other		Reliability	$12,835,000	10/31/2017	10/31/2017	115	41.6	Bottom-up
A in MTEP16	B>A	West	MDU	9121	Heskett-Mandan 115 Upgrade	Replace limiting switches in the Heskett substation on the Mandan 115 kV line.	ND	ND	BaseRel			$125,000	12/31/2016	12/31/2016	115		Bottom-up
A in MTEP16	B>A	West	MDU	11403	TSR F109/A634	Reconductor Coyote-Beulah 115 kV line	ND	ND	TDSP			$350,000	12/31/2015	12/31/2015	115		Externally-Driven
A in MTEP16	B>A	West	MEC	8108	Sub 73 - Dupont 69 kV Line Upgrade	Replace structures to allow a higher operating temperature for the line.	IA	IA	Other		Reliability	$40,000	6/1/2017	6/1/2017	69		Bottom-up
A in MTEP16	B>A	West	MEC	8110	Sub 73 - Elvira Tap 69 kV line upgrade	Replace structures on the Sub 73-Elvira 69 kV line to allow a higher operating temperature.	IA	IA	Other		Reliability	$50,000	6/1/2017	6/1/2017	69		Bottom-up
A in MTEP16	B>A	West	MEC	8112	Buffalo Bill Tap - Elvira Tap 69 kV line upg	Replace structures to allow a higher conductor operating temperature.	IA	IA	Other		Reliability	$25,000	6/1/2017	6/1/2017	69		Bottom-up
A in MTEP16	B>A	West	MEC	9947	Polk City Substation and Lines	Build a new 33 MVA 161-13 kV distribution substation near Polk City, Iowa with 161 kV line taps connecting to the Bittersweet-NE Ankeny 161 kV line.	IA	IA	Other		Distribution	$7,000,000	6/1/2018	6/1/2018	161	13	Bottom-up
A in MTEP16	B>A	West	MEC	9973	Manawa Second Transformer	Add a second 33 MVA 161-13 kV transformer at the Manawa Substation.	IA	IA	Other		Distribution	$1,100,000	10/1/2017	10/1/2017	161	13	Bottom-up
A in MTEP16	B>A	West	MEC	9976	Avoca transformer 69 kV circuit breaker	Add a 69 kV circuit breaker on the low side of Avoca 161-69 kV transformer 8T1.	IA	IA	Other		Reliability	$415,000	12/1/2016	12/1/2016	69		Bottom-up
A in MTEP16	B>A	West	MEC	9980	Teakwood 34.5 kV Reactors	Add two 10 MVAr 34.5 kV reactors at Teakwood Substation.	IA	IA	Other		Reliability	$850,000	10/1/2016	10/1/2016	34.5		Bottom-up
A in MTEP16	B>A	West	MEC	9981	Sub 701-Honey Creek 69 kV Line	Rebuild the Sub 701-Honey Creek 69 kV line.	IA	IA	Other		Reliability	$3,250,000	6/1/2017	6/1/2017	69		Bottom-up
A in MTEP16	B>A	West	MEC	9987	Johnston 161-13 kV Substation	Construct a new Johnston 33 MVA 161-13 kV distribution substation.	IA	IA	Other		Distribution	$2,130,000	11/30/2016	11/30/2016	161	13	Bottom-up
A in MTEP16	B>A	West	MEC	9992	Lake Cornelia-Coulter 69 kV Upgrade	Replace limiting structures on the Lake Cornelia-Coulter 69 kV line to increase line rating.	IA	IA	Other		Reliability	$59,000	7/1/2016	7/1/2016	69		Bottom-up
A in MTEP16	B>A	West	MEC	9993	Humboldt East-Thor 69 kV Upgrade	Upgrade the Humboldt East-Thor 69 kV line by replacing limiting structures.	IA	IA	Other		Reliability	$61,000	4/13/2016	4/13/2016	69		Bottom-up
A in MTEP16	B>A	West	MEC	9996	Eagle Grove Second 69-13 kV transforme	Install a second 69-13 kV Transformer at the Eagle Grove Substation	IA	IA	Other		Distribution	$2,440,000	12/9/2016	12/9/2016	69	13	Bottom-up
A in MTEP16	B>A	West	MEC	10004	Sub 18 replace transformer 8T3	Replace 161-69 kV transformer 8T3 at Sub 18 with a 167 MVA unit.	IA	IA	Other		Reliability	$1,080,000	6/1/2018	6/1/2018	161	69	Bottom-up
A in MTEP16	B>A	West	MEC	10005	Replace 161 kV Circuit Breaker at Plymou	Replace 161 kV circuit breaker 9610 at Plymouth Substation	IA	IA	BaseRel			$264,000	12/8/2015	12/8/2015	161		Bottom-up
A in MTEP16	B>A	West	MEC	10006	Sycamore Substation: replace three 161 k	Replace 161 kV circuit breakers AG805, AG812 and AG816 at Sycamore Substation.	IA	IA	BaseRel			$685,000	12/31/2016	12/31/2016	161		Bottom-up
A in MTEP16	B>A	West	MEC	10009	Bondurant: Replace 161 kV circuit breaker	Replace 161 kV circuit breaker AH810 at Bondurant Substation.	IA	IA	BaseRel			$325,000	10/31/2016	10/31/2016	161		Bottom-up
A in MTEP16	B>A	West	MEC	10503	Tate & Lyle Bus Tie Breaker	Add a 161 kV bus tie circuit breaker at Tate & Lyle Substaiton	IA	IA	BaseRel			$443,000	10/20/2016	10/20/2016	161		Bottom-up

Appendix A-1: Preliminary MTEP16 Appendix A Generator Interconnection Project and Market Efficiency Project Cost Allocations by Pricing Zones Subject to Approval for Appendix A

Values shown below are subject to change depending on actual project costs [1]

Project ID	Project Type	Region	ISD	Zone	Total Shared Cost[2]	AMIL	AMMO	ATC	BREC	CLEC	CWLD	CWLP	DEI
11883	MEP	West	Jan-22	Various	108,000,000	2,685,184	1,863,318	2,757,273	401,103		76,352	118,827	1,765,163
10425	GIP	East	Sep-17	ITC	$7,575,000	$13,392	$12,263	$18,146	$2,640		$502	$593	$11,617
10743	GIP	East	Sep-15	METC	$360,500	$34,180	$31,298	$46,314	$6,737		$1,282	$1,513	$29,650
10744	GIP	East	May-16	METC	$8,851,100								
10867	GIP	West	Aug-16	MEC	$300,000	$28,262	$25,879	$38,295	$5,571		$1,060	$1,251	$24,516
10868	GIP	West	Jul-16	MEC	$575,000	$54,170	$49,602	$73,400	$10,678		$2,033	$2,397	$46,989
11203	GIP	West	Nov-12	MEC	288,200	27,151	24,861	36,789	5,352		1,019	1,201	23,552
11204	GIP	West	Dec-11	MEC	75,410	7,104	6,505	9,626	1,400		267	314	6,163
11043	GIP	East	Apr-16	ITC	$25,000	$2,355	$2,157	$3,191	$464		$88	$104	$2,043
11583	GIP	East	Sep-17	ITC	$4,406,000	$83,016	$76,016	$112,487	$16,364		$3,115	$3,674	$72,012
11584	GIP	East	Sep-17	ITC	4,374,000	82,413	75,464	111,670	16,245		3,092	3,647	71,489
11603	GIP	East	Sep-17	ITC	4,350,000	81,961	75,050	111,057	16,156		3,075	3,627	71,097
11604	GIP	East	Jun-18	ITC	68,000								
				MISO Total	**$139,248,210**	**$3,099,190**	**$2,242,415**	**$3,318,248**	**$482,709**		**$91,886**	**$137,148**	**$2,124,290**

Notes:

(1) The allocations shown above are estimates that are based on current estimates of project costs and projected in-service dates. The actual allocation amounts will vary depending on the actual project costs and actual in-service dates.

(2) Total Shared Cost reflects the project cost subject to sharing and allocated to pricing zones in MISO. This does not include 50% or 90% of the Network Upgrade cost of the Generator Interconnection Projects (GIP) assgined to the Generators .

3) Total Project Cost with 100% GIP includes the total network upgrade costs for GIPs including the 50% or 90% assigned to the generators. This does not take into account those GIPs with agreements for Transmission Owners to reimburse the generators for 100% of their Network Upgrade costs.

Please contact Eric Thoms at ethoms@misoenergy.org with any questions

Pricing Zone														
DPC	EATO	ELTO	EMTO	ETTO	GRE	HE	IPL	ITC	ITCM	LAFA	MDU	MEC	METC	MI13AG
2,395,393					2,911,444	162,646	663,939	2,454,682	21,874,935		1,474,239	31,866,974	1,895,050	137,900
$1,653					$2,009	$1,070	$4,369	$7,449,004	$5,541		$1,017	$8,071	$12,471	$908
$4,219					$5,128	$2,732	$11,152	$41,231	$14,141		$2,596	$20,601	$31,831	
													$8,851,100	
$3,488					$4,240	$2,259	$9,221	$34,093	$11,693		$2,147	$17,034	$26,320	$1,915
$6,686					$8,126	$4,330	$17,674	$65,345	$22,412		$4,115	$32,649	$50,447	$3,671
3,351					4,073	2,170	8,859	32,752	11,233		2,062	16,364	25,285	1,840
877					1,066	568	2,318	8,570	2,939		540	4,282	6,616	481
$291					$353	$188	$768	$2,841	$974		$179	$1,420	$2,193	$160
$10,246					$12,454	$6,635	$27,086	$3,624,942	$34,346		$6,306	$50,035	$77,311	$5,626
10,172					12,363	6,587	26,890	3,598,615	34,097		6,260	49,671	76,750	5,585
10,116					12,296	6,551	26,742	3,578,869	33,910		6,226	49,399	76,328	5,554
								68,000						
$2,446,492					**$2,973,552**	**$195,737**	**$799,020**	**$20,958,943**	**$22,046,220**		**$1,505,688**	**$32,116,500**	**$11,131,703**	**$163,639**

MI13ANG	MP	MPW	NIPS	NSP	OTP	SIPC	SME	SMMPA	VECT	Total	Total Project Cost with 100% GIP[3]
36,163	4,525,458	902,755	854,327	21,386,142	3,577,986	174,279		747,961	290,507	108,000,000	108,000,000
$238	$3,123	$229	$5,622	$14,757	$2,469	$869		$516	$1,912	7,575,000	$15,150,000
$607	$7,970	$584	$14,350	$37,665	$6,302	$2,218		$1,317	$4,880	360,500	$3,605,000
										8,851,100	$17,702,200
$502	$6,590	$483	$11,866	$31,144	$5,211	$1,834		$1,089	$4,035	300,000	$3,000,000
$963	$12,631	$925	$22,743	$59,693	$9,987	$3,516		$2,088	$7,733	575,000	$5,750,000
483	6,331	464	11,399	29,919	5,006	1,762		1,046	3,876	288,200	2,882,000
126	1,657	121	2,983	7,829	1,310	461		274	1,014	75,410	754,100
$42	$549	$40	$989	$2,595	$434	$153		$91	$336	25,000	$250,000
$1,475	$19,358	$1,417	$34,853	$91,480	$15,305	$5,388		$3,199	$11,852	4,406,000	$8,812,000
1,465	19,217	1,407	34,600	90,816	15,194	5,349		3,176	11,766	4,374,000	8,748,000
1,457	19,112	1,399	34,410	90,318	15,111	5,320		3,159	11,701	4,350,000	8,700,000
										68,000	136,000
$43,520	**$4,621,996**	**$909,824**	**$1,028,143**	**$21,842,358**	**$3,654,312**	**$201,150**		**$763,917**	**$349,611**	**$139,248,210**	**$183,489,300**

Appendix A-2.1. *Indicative* Schedule 26 Annual Charges by MISO Pricing Zone for new MTEP16 Generator Interconection Projects and Market Efficiency Projects Subject to Approval for Appendix A

THE VALUES SHOWN BELOW (IN NOMINAL $) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE

	Year															
Pricing Zone	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
AMIL	46,450	86,180	84,670	83,160	81,650	550,762	541,113	531,464	521,814	512,165	502,516	492,867	483,217	473,568	463,919	454,270
AMMO	42,533	78,913	77,531	76,148	74,765	399,959	392,929	385,898	378,867	371,836	364,806	357,775	350,744	343,714	336,683	329,652
ATC	62,939	116,773	114,727	112,681	110,635	591,846	581,442	571,038	560,634	550,231	539,827	529,423	519,019	508,615	498,212	487,808
BREC	9,156	16,987	16,689	16,392	16,094	86,096	84,583	83,069	81,556	80,043	78,529	77,016	75,502	73,989	72,475	70,962
CLEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CWLD	1,743	3,234	3,177	3,120	3,064	16,389	16,101	15,813	15,525	15,236	14,948	14,660	14,372	14,084	13,796	13,508
CWLP	2,056	3,814	3,747	3,680	3,613	24,373	23,946	23,519	23,092	22,665	22,238	21,811	21,384	20,957	20,530	20,103
DEI	40,293	74,756	73,446	72,137	70,827	378,890	372,230	365,570	358,909	352,249	345,589	338,928	332,268	325,608	318,947	312,287
DPC	5,733	10,637	10,451	10,264	10,078	429,723	422,276	414,829	407,382	399,934	392,487	385,040	377,593	370,146	362,699	355,252
EATO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ELTO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMTO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ETTO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRE	6,968	12,928	12,702	12,475	12,249	522,301	513,249	504,197	495,146	486,094	477,043	467,991	458,940	449,888	440,837	431,785
HE	3,713	6,888	6,768	6,647	6,526	34,912	34,298	33,684	33,071	32,457	31,843	31,230	30,616	30,002	29,388	28,775
IPL	15,156	28,118	27,626	27,133	26,640	142,514	140,009	137,504	134,998	132,493	129,988	127,483	124,978	122,472	119,967	117,462
ITC	1,474,291	4,295,557	4,230,289	4,156,956	4,083,623	4,440,513	4,359,740	4,278,966	4,198,193	4,117,419	4,036,646	3,955,872	3,875,099	3,794,326	3,713,552	3,632,779
ITCM	19,218	35,655	35,030	34,406	33,781	3,867,096	3,800,165	3,733,234	3,666,303	3,599,373	3,532,442	3,465,511	3,398,580	3,331,650	3,264,719	3,197,788
LAFA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MDU	3,528	6,546	6,432	6,317	6,202	264,472	259,889	255,305	250,722	246,139	241,555	236,972	232,389	227,805	223,222	218,639
MEC	27,996	51,942	51,031	50,121	49,211	5,633,509	5,536,005	5,438,502	5,340,998	5,243,495	5,145,992	5,048,488	4,950,985	4,853,482	4,755,978	4,658,475
METC	2,032,858	2,038,162	2,005,060	1,971,958	1,938,856	2,237,893	2,199,047	2,160,201	2,121,355	2,082,508	2,043,662	2,004,816	1,965,970	1,927,124	1,888,278	1,849,432
MI13AG	2,635	5,336	5,242	5,148	5,054	29,129	28,617	28,105	27,593	27,081	26,569	26,057	25,545	25,033	24,521	24,009
MI13ANG	825	1,532	1,505	1,478	1,451	7,762	7,626	7,489	7,353	7,217	7,080	6,944	6,807	6,671	6,534	6,398
MP	10,831	20,096	19,743	19,391	19,039	811,847	797,778	783,709	769,639	755,570	741,500	727,431	713,362	699,292	685,223	671,153
MPW	793	1,471	1,446	1,420	1,394	159,591	156,829	154,067	151,304	148,542	145,780	143,018	140,256	137,494	134,731	131,969
NIPS	19,501	36,182	35,548	34,914	34,280	183,380	180,157	176,933	173,710	170,486	167,263	164,039	160,816	157,592	154,368	151,145
NSP	51,186	94,966	93,302	91,638	89,974	3,836,581	3,770,093	3,703,604	3,637,116	3,570,627	3,504,139	3,437,651	3,371,162	3,304,674	3,238,185	3,171,697
OTP	8,564	15,888	15,610	15,331	15,053	641,875	630,751	619,628	608,504	597,380	586,256	575,132	564,009	552,885	541,761	530,637
SIPC	3,015	5,593	5,495	5,397	5,299	35,747	35,120	34,494	33,868	33,242	32,615	31,989	31,363	30,737	30,110	29,484
SME	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SMMPA	1,790	3,321	3,263	3,205	3,147	134,181	131,856	129,530	127,205	124,880	122,554	120,229	117,903	115,578	113,253	110,927
VECT	6,631	12,303	12,088	11,872	11,656	62,357	61,261	60,165	59,069	57,972	56,876	55,780	54,684	53,588	52,492	51,396
Grand Total	**3,900,403**	**7,063,779**	**6,952,617**	**6,833,389**	**6,714,162**	**25,523,698**	**25,077,107**	**24,630,516**	**24,183,926**	**23,737,335**	**23,290,744**	**22,844,153**	**22,397,563**	**21,950,972**	**21,504,381**	**21,057,790**

Notes:

1) The indicative annual charges shown only reflect new MTEP16 projects and would be additive to the indicative annual Schedule 26 charges shown in the posted spreadsheet at the following link on the MISO website under the MTEP Study Information section:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies/Indicative annual charges for approved BRP, GIP, and MEP (Schedule 26)

2) The Annual Revenue Requirement for the MEP has been calculated using the estimated Annual Charge Rate based on the methodology described in Attachment GG. The Annual Charge Rate is estimated using Transmission Owner's Attachment O data as of December 2015 and assumes 40-year straight-line depreciation.

3) For approved projects with recovery for Construction Work in Progress, charges are phased-in based on an assumed schedule, see posted spreadsheet referenced in note one.

4) For approved projects without approval for Construction Work in Progress recovery, charges start based on the estimated in-service date and whether the constructing Transmission Owner uses forward-looking or historic rate formulas. First -year charges are adjusted according to the month the project goes in-service and whether the constructing Transmission Owner used forward-looking or historic rate formulas.

5) Please contact Eric Thoms at ethoms@misoenergy.org with any questions

Appendix A-2.2. Indicative MTEP06 through MTEP16 Cost Allocation Summary for Baseline Reliability, Generation Interconnection, and Market Efficiency Projects

Pricing Zone	Total Approved Cost Shared Transmission Investment	Costs Allocated for Projects Located Outside Pricing Zone	Costs Allocated for Projects Located within the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	146,522,797	43,510,144	120,820,525	164,330,668
AMMO	84,393,688	32,429,254	78,461,502	110,890,756
ATC	956,579,037	90,482,992	796,475,992	886,958,985
BREC	5,232,998	5,497,117	310,811	5,807,928
CLEC	-	-	-	
CWLD	-	1,064,906	-	1,064,906
CWLP	7,049,435	1,762,509	7,049,435	8,811,944
DPC	18,813,435	6,366,503	8,875,007	15,241,510
DUK	45,958,666	112,927,536	41,834,500	154,762,036
EATO	-	-	-	-
ELTO	-	-	-	-
EMTO	-	-	-	-
ETTO	-	-	-	-
FE	16,562,745	36,824,187	14,712,880	51,537,067
GRE	200,625,548	31,160,542	9,574,094	40,734,636
HE	14,729,467	12,993,680	354,277	13,347,957
IPL	16,256,948	25,060,434	3,510,642	28,571,077
ITC	126,426,146	44,446,868	114,969,264	159,416,132
ITCM	209,283,184	63,566,668	140,622,608	204,189,276
LAFA	-	-	-	
MDU	9,406,937	11,064,365	9,198,681	20,263,045
MEC	1,839,051	37,750,535	101,705	37,852,240
METC	450,782,435	90,794,018	437,888,891	528,682,909
MI13AG	921,025	1,929,470	731,284	2,660,754
MI13ANG	-	2,698,598	-	2,698,598
MP	123,668,656	108,311,396	32,407,353	140,718,749
MPW	-	1,062,589	-	1,062,589
NIPS	21,548,296	25,790,244	20,423,252	46,213,496
NSP	647,445,701	311,034,287	342,447,208	653,481,495
OTP	181,453,238	116,585,247	46,260,542	162,845,789
SIPC	-	2,007,528	-	2,007,528
SME	-	-	-	-
SMMPA	49,149,906	19,911,437	3,889,817	23,801,254
VECT	203,567,165	6,248,150	64,015,031	70,263,181
Total	**$3,538,216,504**	**$1,243,281,203**	**$2,294,935,301**	**$3,538,216,504**

Note: The Duke Pricing Zone includes the withdrawn DEO and DEK TOs. Also, FE is listed as a Pricing Zone but has withdrawn.

Appendix A-2.3. ***Indicative MTEP 16*** **Cost Allocation Summary for MTEP16 New Generator Interconnection (GIP) and Market Efficiency Projects**

Pricing Zone	Total Approved Cost Shared Transmission Investment [1]	Costs Allocated for Projects Located Outside Pricing Zone	Costs Allocated for Projects Located within the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	-	3,099,190	-	3,099,190
AMMO	-	2,242,415	-	2,242,415
ATC	-	3,318,248	-	3,318,248
BREC	-	482,709	-	482,709
CLEC	-	-	-	-
CWLD	-	91,886	-	91,886
CWLP	-	137,148	-	137,148
DEI	-	2,124,290	-	2,124,290
DPC	-	2,446,492	-	2,446,492
EATO	-	-	-	-
ELTO	-	-	-	-
EMTO	-	-	-	-
ETTO	-	-	-	-
GRE	-	2,973,552	-	2,973,552
HE	-	195,737	-	195,737
IPL	-	799,020	-	799,020
ITC	20,798,000	2,636,672	18,322,271	20,958,943
ITCM	54,000,000	11,108,753	10,937,467	22,046,220
LAFA	-	-	-	-
MDU	-	1,505,688	-	1,505,688
MEC	1,238,610	32,046,171	70,329	32,116,500
METC	9,211,600	2,248,772	8,882,931	11,131,703
MI13AG	-	163,639	-	163,639
MI13ANG	-	43,520	-	43,520
MP	-	4,621,996	-	4,621,996
MPW	-	909,824	-	909,824
NIPS	-	1,028,143	-	1,028,143
NSP	54,000,000	11,149,287	10,693,071	21,842,358
OTP	-	3,654,312	-	3,654,312
SIPC	-	201,150	-	201,150
SME	-	-	-	-
SMMPA	-	763,917	-	763,917
VECT	-	349,611	-	349,611
Total	**$139,248,210**	**$90,342,141**	**$48,906,069**	**$139,248,210**

Notes:

(1) This information has been provided per prior stakeholder request and includes ten MTEP16 Generator Inconnection Projects and one MEP project. For purposes of this presentation, the costs of the MEP assets that will physically reside in each pricing zone have been estimated and are subject to change as more information becomes available.

Appendix A-3. Indicative MVP Usage Rates for Approved MVPs (in Nominal dollars)

THE VALUES SHOWN BELOW (IN Nominal $) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

Year	Total Indicative MVP Usage Rate ($/MWh)	Year	Total Indicative MVP Usage Rate ($/MWh)
2017	$1.39	2037	$1.49
2018	$1.63	2038	$1.47
2019	$1.84	2039	$1.44
2020	$1.86	2040	$1.42
2021	$1.92	2041	$1.39
2022	$1.90	2042	$1.36
2023	$1.88	2043	$1.34
2024	$1.87	2044	$1.31
2025	$1.84	2045	$1.29
2026	$1.81	2046	$1.27
2027	$1.78	2047	$1.24
2028	$1.75	2048	$1.22
2029	$1.72	2049	$1.19
2030	$1.69	2050	$1.17
2031	$1.66	2051	$1.15
2032	$1.63	2052	$1.13
2033	$1.60	2053	$1.10
2034	$1.58	2054	$1.06
2035	$1.55	2055	$1.04
2036	$1.52	2056	$0.99

Notes:

1) Indicative MVP Usage Rate based on approved Multi-Value Projects through September 2016 and information provided in the MTEP Quarterly Status Report as of 09/30/16.

2) Annual MISO other than exports to PJM, are based on 2014 values with years 2017-2056 escalated assuming an annual energy growth rate of 0.8% consistent with the assumed energy growth rate used in the MTEP16 Business as Usual Future. The PJM exports are based on year-to-date June 2016 MWhs annualized with years 2017 - 2056 escalated as described above.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each constructing Transmission Owner based on the methodology described in Attachment MM. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2015 and assumes 40-year straight-line depreciation.

4) For approved projects with recovery for Construction Work in Progress, charges are phased-in based on an assumed schedule.

5) For the Michigan Thumb MVP the project was assumed to be phased in-service equally over the 2013-2015 period.

6) Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO website at the following URL under the MTEP Study information section:

https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies/Indicative annual charges for approved Multi Value Projects (Schedule 26-A)

7) Please contact Eric Thoms at ethoms@misoenergy.org with any questions

MISO TRANSMISSION EXPANSION PLAN 2016

Appendix E2

EGEAS Assumptions Document

Table of Contents

Preface

This document details the study assumptions used to produce the Electric Generation Expansion Analysis Software (EGEAS) generation expansion plans for the five scenarios modeled in MTEP16. These are the scenarios which were developed through the Planning Advisory Committee beginning in the Fall of 2014 and voted on in early 2015.

Base data assumptions in the associated Powerbase database are presented and include fuel forecasts, new unit construction costs, emissions costs, Renewable Portfolio Standard (RPS) assumptions and regional demand and energy projections. The five MTEP16 scenarios for which assumptions are shown are:

- Business as Usual (BAU)
- High Demand (HD)
- Low Demand (LD)
- Regional Clean Power Plan (CPP)
- Sub-Regional Clean Power Plan (SCPP)

E2.1 MTEP16 Futures Narratives, Matrix and Uncertainty Variables

The futures matrix workbook is a compilation of tables aimed at detailing many of the major modeling assumptions used in each of the MTEP16 scenarios. The workbook covers the following areas: the matrix and uncertainty variables, natural gas modeling assumptions, capital costs, carbon costs, and generation retirements.

The futures narratives provide a high-level overview of the conditions that are modeled in each scenario. The matrix can be thought of as the bridge between the narratives and the final values that define each uncertainty variable. The matrix allows for easy cross-comparison of the modeling assumptions that went into building the scenarios. Within the matrix, the levels low (L), medium (M) and high (H) indicate the associated value of the variable in question. Each L, M or H is directly tied to a value within the uncertainty variables (Table E2.2).

As an example, the intersection of the Business as Usual row in the matrix and the demand growth rate column yields an M value. To find the actual growth rate percentage associated with M, refer to the intersection of the M column in the uncertainty variables table () and the Demand Growth Rate row. The resulting value for the Business as Usual demand growth rate is 0.8 percent. This procedure can be repeated as necessary to find all values associated with each L, M, and H in the matrix, noting that all column headings in the matrix (Table E2.1) are transposed to row headings in the uncertainty variables table (Table E2.2).

The following narratives describe the MTEP16 future scenarios and their key drivers:

- "The baseline, or **Business as Usual**, future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into the Module E Capacity Tracking (MECT) tool. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable and enforceable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, a total of 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire."
- "The **High Demand** future is designed to capture the effects of increased economic growth resulting in higher energy costs and medium – high gas prices. The magnitude of demand and energy growth is determined by using the upper bound of the Load Forecast Uncertainty metric and also includes forecasted load increases in the South region. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are incorporated. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire. Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear The Limited Growth future is designed to capture the effects of the economy turning back toward recession-like levels. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are included.
- "The **Low Demand** future is designed to capture the effects of reduced economic growth resulting in lower energy costs and medium – low gas prices. The magnitude of demand and energy growth is determined by using the lower bound of the Load Forecast Uncertainty metric.

All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire. Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric." Hydro units will retire in the year they reach 100 years of age.

- "The **Regional Clean Power Plan** future focuses on several key items from a footprint wide level which in combination result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include the following:
  - To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including existing or announced retirements.
  - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.
  - Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
  - Solar and wind include an economic maturity curve to reflect declining costs over time.
  - Demand and energy growth rates are modeled at levels as reported in Module E.
- *"The **Sub-Regional Clean Power Plan** future focuses on several key items from a zonal or state level which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include the following:*
  - *To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, existing or announced retirements.*
  - *20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.*
  - *These increased retirements and carbon cost levels from the Regional CPP Future are consistent with regional/sub-regional CPP assessments performed by MISO and other organizations since the CPP's introduction.*
  - *Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.*
  - *Solar and wind include an economic maturity curve to reflect declining costs over time.*
  - *Demand and energy growth rates are modeled at levels as reported in Module E.*

MTEP16 FUTURES MATRIX																															
	Uncertainties																														
	Capital Costs														Demand and Energy					Fuel Cost (Starting			Fuel Escalations			Emission Costs			Other Variables		
Future	Coal	CC	CT	Nuclear	Wind Onshore	IGCC	IGCC w/ CCS	CC w/ CCS	Pumped Storage Hydro	Compressed Air Energy Storage	Photovoltaic	Biomass	Conventional Hydro	Wind Offshore	Demand Response Level	Energy Efficiency Level	Demand Growth Rate	Energy Growth Rate	Natural Gas Forecast	Oil	Coal	Uranium	Oil	Coal	Uranium	SO_2	NO_x	CO_2	Inflation	Retirements	Renewable Portfolio Standards
Business As Usual	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	M	L	M
High Demand	H	H	H	H	H	H	H	H	H	H	H	H	H	H	M	M	H	H	M	M	M	M	H	H	H	L	L	L	H	M	M
Low Demand	L	L	L	L	M	L	L	L	L	L	M	L	L	L	M	M	L	L	L	L	L	M	L	L	L	L	L	L	L	M	M
Regional CPP Compliance	H	H	H	M	L	M	M	M	M	M	L	M	M	M	M	H	M	M	H	L	L	M	M	M	M	L	L	M	M	H	H
Sub-Regional CPP Compliance	H	H	H	M	L	M	M	M	M	M	L	M	M	M	M	H	M	M	H	L	L	M	H	H	H	L	L	H	H	H	H

Table E2.1: **MTEP16 futures matrix**

MTEP16 UNCERTAINTY VARIABLES				
Uncertainty	**Unit**	**Low (L)**	**Mid (M)**	**High (H)**
New Generation Capital Costs[1]				
Coal	($/KW)	2,279	3,039	3,799
CC	($/KW)	795	1,060	1,324
CT	($/KW)	525	700	875
Nuclear	($/KW)	4,296	5,728	7,160
Wind-Onshore	($/KW)	1,750	2,063	2,579
IGCC	($/KW)	2,940	3,919	4,899
IGCC w/ CCS	($/KW)	5,126	6,835	8,544
CC w/ CCS	($/KW)	1,627	2,170	2,712
Pumped Storage Hydro	($/KW)	4,108	5,477	6,846
Compressed Air Energy Storage	($/KW)	971	1,295	1,618
Photovoltaic	($/KW)	1,750	3,009	5,014
Biomass	($/KW)	3,196	4,261	5,326
Conventional Hydro	($/KW)	2,281	3,041	3,801
Wind-Offshore	($/KW)	4,840	6,453	8,066
Demand and Energy				
Baseline 20-Year Demand Growth Rate[2]	%	0.11%	0.75%	1.55%
Baseline 20-Year Energy Growth Rate[3]	%	0.19%	0.82%	1.61%
Demand Response Level	%	State mandates only	State mandates and goals	
Energy Efficiency Level	%	State mandates only	State mandates and goals	State mandates and goals + 1/2 of EPA CPP growth[4]
Natural Gas				
Natural Gas[5]	($/MMBtu)	Bentek -20%	Bentek forecast from Phase III Gas Study	Bentek +20%
Fuel Prices (Starting Values)				
Oil	($/MMBtu)	Powerbase default -20%	Powerbase default[6]	Powerbase default + 20%
Coal	($/MMBtu)	Powerbase default -20%	Powerbase default[7]	Powerbase default + 20%
Uranium	($/MMBtu)	0.91	1.14	1.37
Fuel Prices (Escalation Rates)				
Oil	%	2.0	2.5	4.0
Coal	%	2.0	2.5	4.0
Uranium	%	2.0	2.5	4.0
Emissions Costs				
SO_2	($/ton)	0	0	500
NO_x	($/ton)	0	0	NO_x: 500 Seasonal NO_x: 1000
CO_2	($/ton)	0	25	40
Other Variables				
Inflation	%	2.0	2.5	4.0
Retirements	MW	12.6 GW Coal MATS Retirements	MATS coal + age-related gas/oil/hydro = 22 GW	Regional: MATS + age-related + 14 GW CPP Coal = 36 GW Sub-Regional: MATS + age-related + 20 GW CPP Coal = 41 GW
Renewable Portfolio Standards	%	State mandates only	State mandates and goals	State mandates and goals + cost maturity curves

Table E2.1 E2.1: MTEP16 uncertainty variables

Notes on uncertainty variables:

[1] All costs are overnight construction costs in 2014 dollars; sourced from EIA and escalated according to the GDP Implicit Price Deflator; H and L values are 20% +/- from the M value, except where otherwise noted
[2] Mid values for years 1 - 10 of demand growth are derived from Module-E; Years 11-20 are extrapolated; H & L values are derived using LFU metric

[3] Energy values are calculated using the corresponding demand forecast and historical load factors

[4] Energy Efficiency grows at half the rate proposed by the EPA in the Clean Power Plan for the MISO system

[5] Bentek forecast prices reflect the Henry Hub natural gas price

[6] Powerbase default for oil is $19.39/MMBtu

[7] Powerbase range for coal is $1 to $4, with an average value of $1.69/MMBtu

E2.2 Regional Resource Forecasting

Regional Resource Forecasted (RRF) units are an output of step 1 of the MTEP process. The Generation Interconnection Queue is the primary source for out-year capacity; however, the queue is generally limited to five years out or less for new capacity. For this reason, a capacity expansion tool is used to supplement the out years to maintain the load-to-resource balance and Planning Reserve Margin (PRM) target. To use RRF units in a production cost model, they must be sited at buses in the powerflow model. Units are sited based on stakeholder-defined rules and criteria.

The Electric Generation Expansion Analysis System (EGEAS), created by the Electric Power Research Institute (EPRI), is the capacity expansion software tool used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. The objective function of the MTEP15 study optimization aims to minimize the 20-year capital and production costs, with a reserve margin requirement indicating when and what type of resources will be added to the system. The following sections focus on data assumptions and methodologies specific to EGEAS applications.

E2.2.1 Resource Mix

Each planning region within the Eastern Interconnect is made up of a diverse mix of capacity resources. This diversity is clearly demonstrated in Table E2.3 and the pie charts that follow. Table E2.3 shows the nameplate capacity (in MW) for all existing, under construction and planned units.

Region	Coal	Nuclear	Gas	Wind	Solar	Hydro	Pumped Storage	Oil	Other
MISO	71,507	14,953	70,725	16,171	125	2,184	0	4,108	1,429
NYISO	1,380	5,293	21,716	1,794	15	4,948	1,407	4,847	1,412
PJM	72,783	37,144	80,031	9,922	706	3,104	5,610	10,222	2,462
SERC	39,609	22,018	49,578	255	911	6,721	4,626	2,371	646
SPP	24,421	2,449	31,625	14,423	60	4,528	474	1,324	86
TVA*	21,931	8,077	20,196	1,985	66	5,823	1,856	59	5

*For EGEAS analysis, Associated Electric Cooperative Inc. (AECI), Louisville Gas & Electric and Kentucky Utilities are combined with the Tennessee Valley Authority (TVA)

Table E2.1 E2.2: MTEP16 existing, under construction and planned units

Figure E2.1 through E2.6 show the resource mix breakdowns as a percentage of total generation capacity for each modeled Eastern Interconnect region.

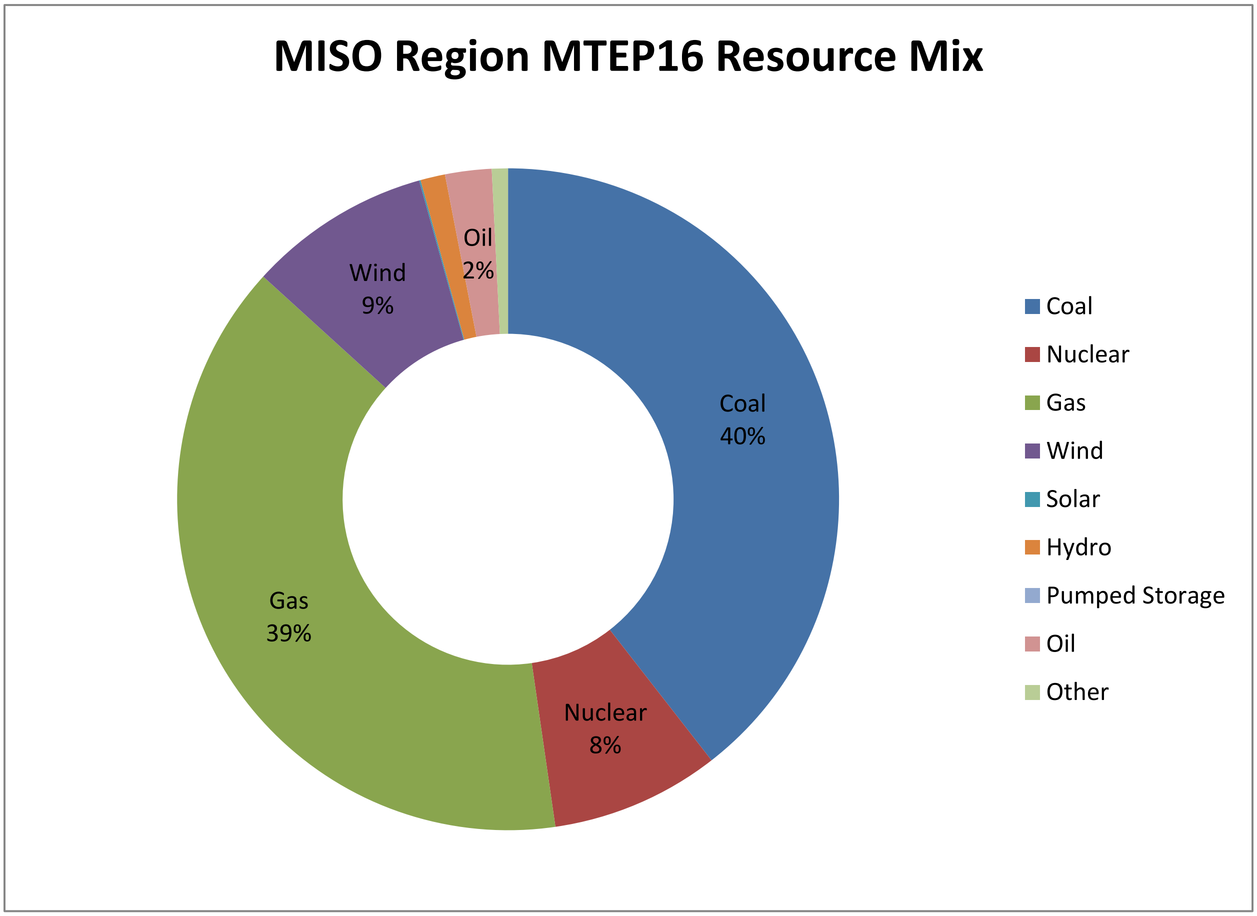

Figure E2.1: MISO resource mix

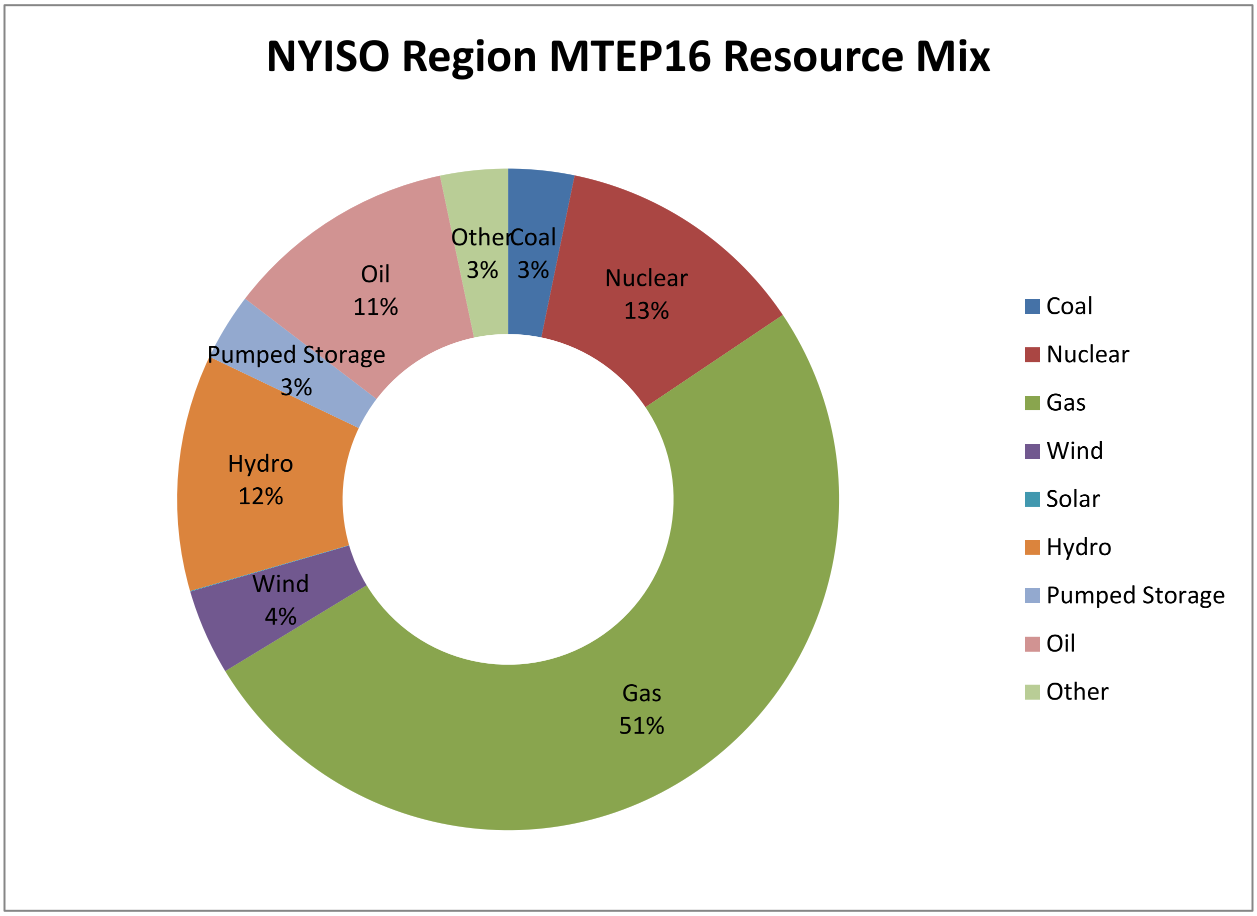

Figure E2.2: NYISO resource mix

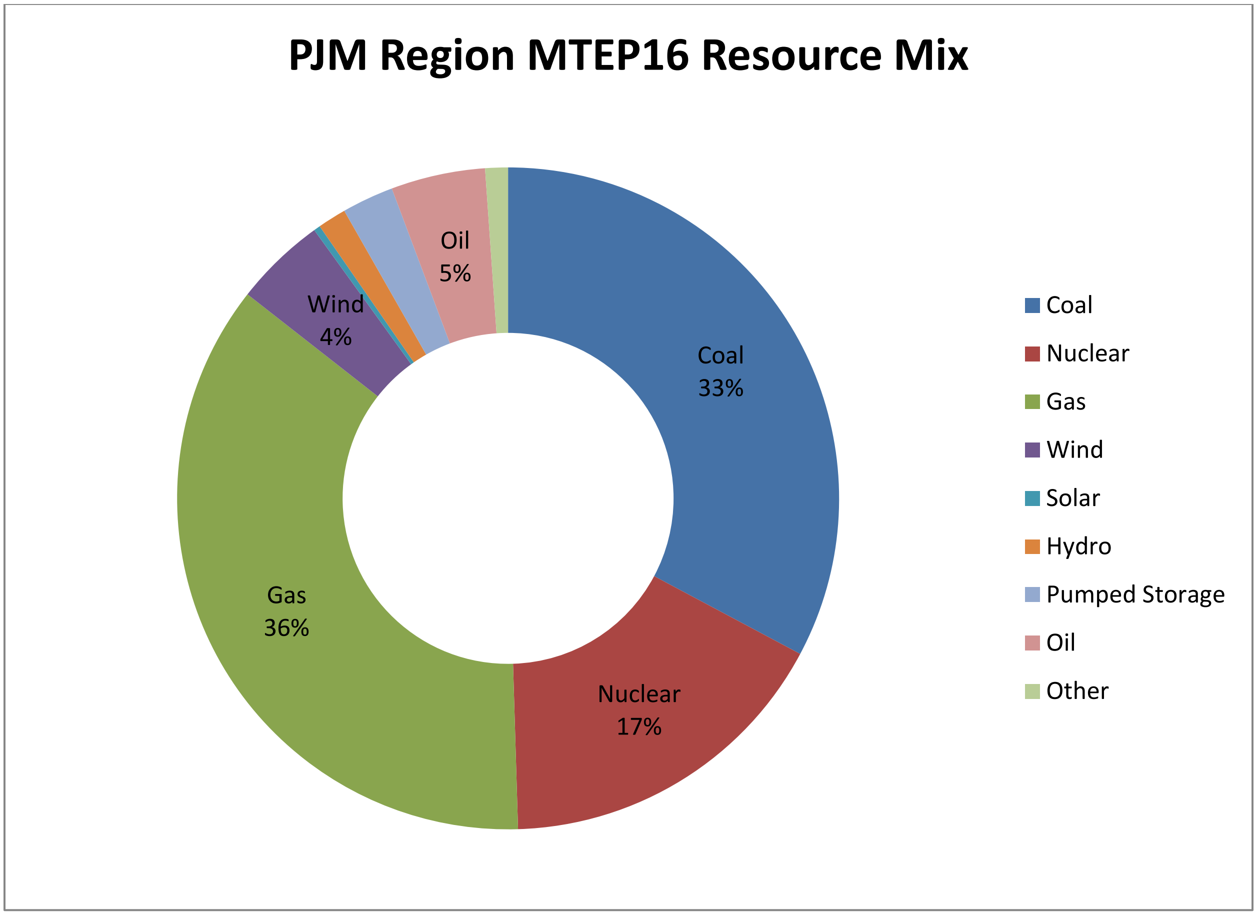

Figure E2.3: PJM resource mix

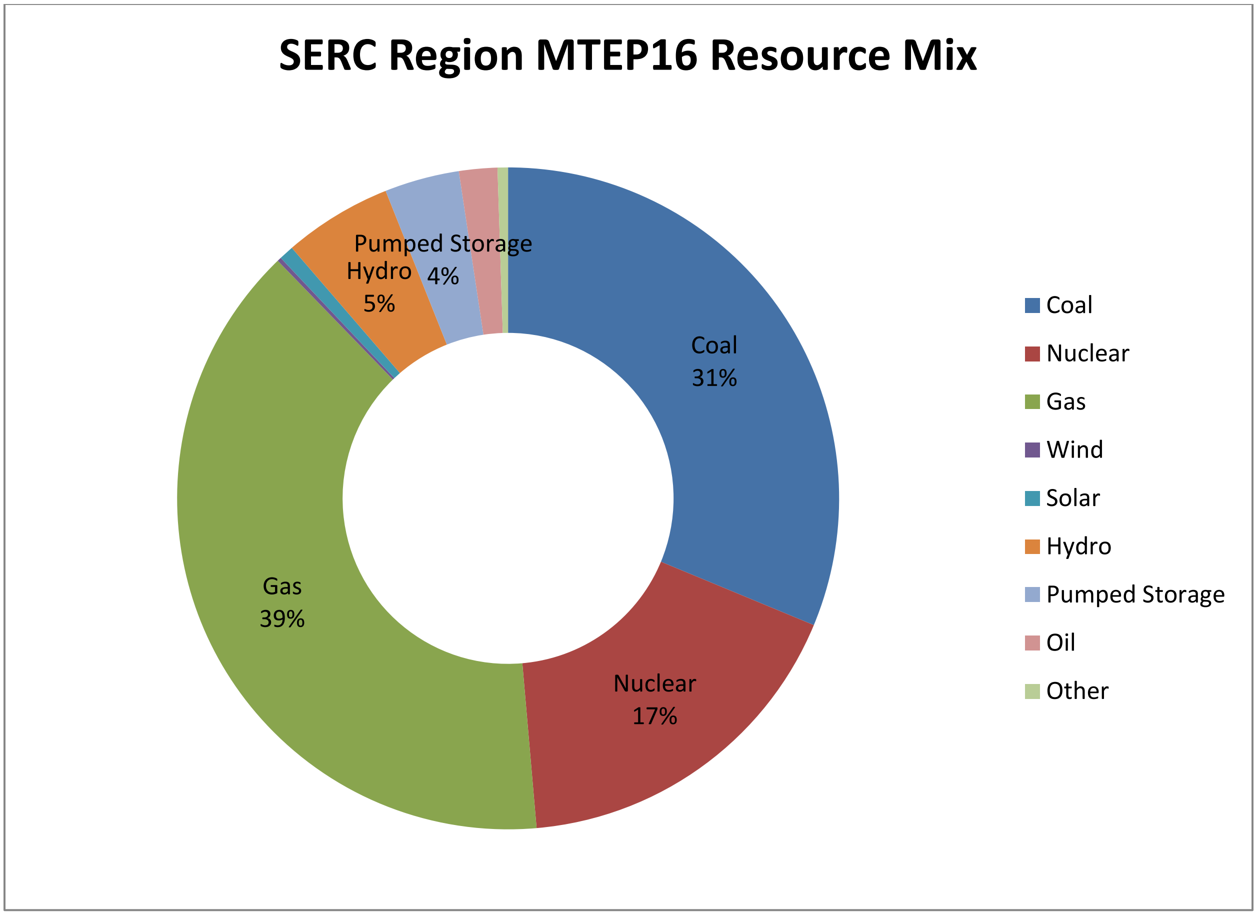

Figure E2.4: SERC resource mix

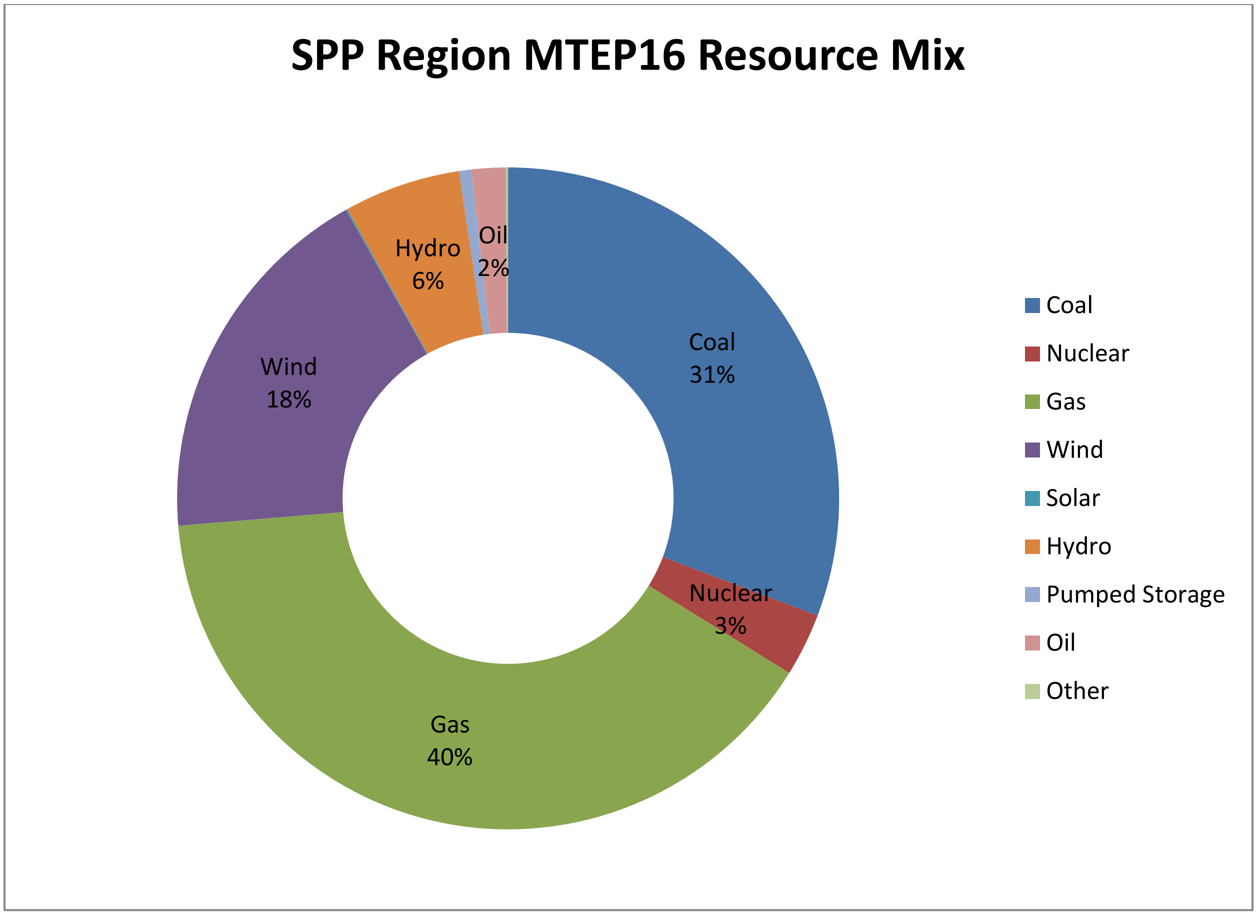

Figure E2.5: SPP resource mix

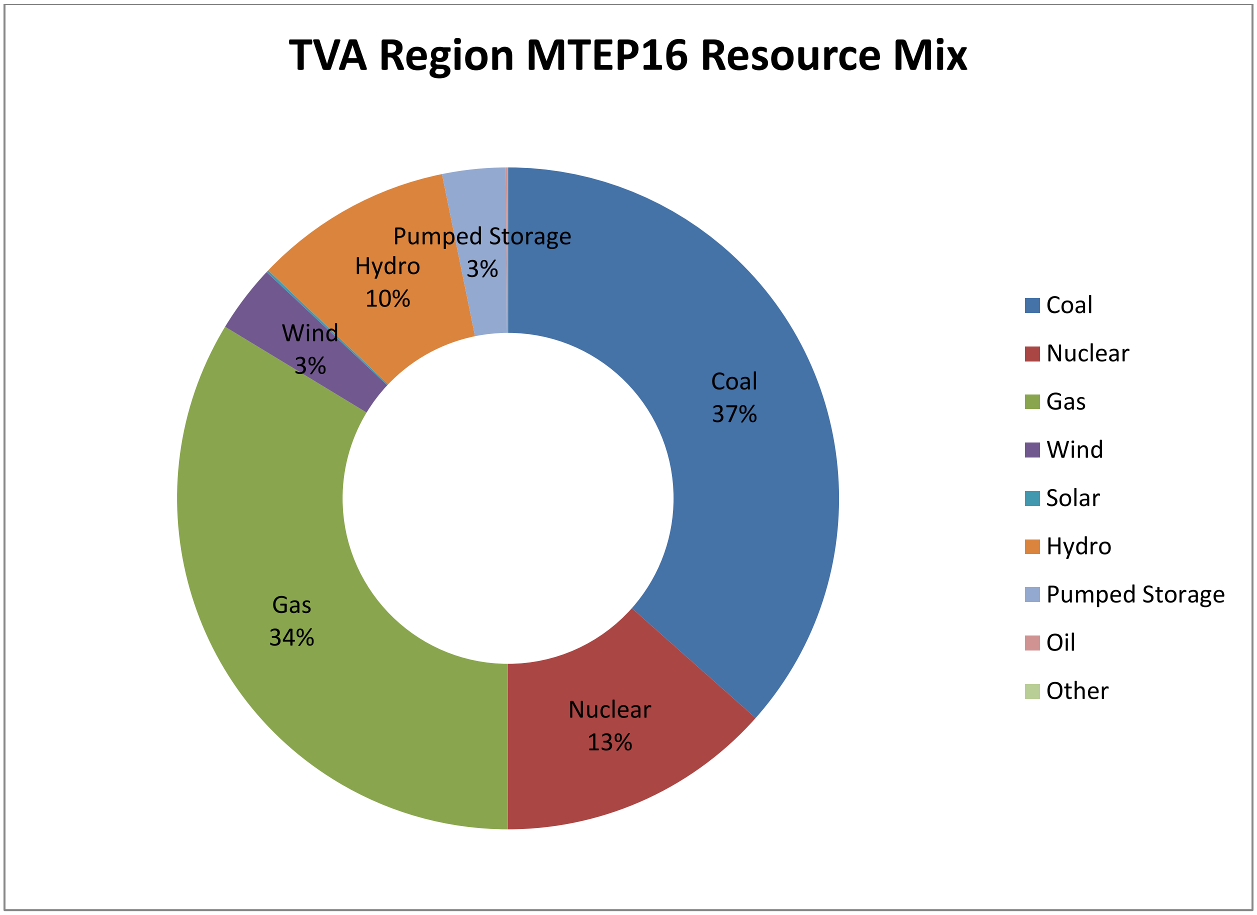

Figure E2.6: TVA resource mix

E2.2.2 Regional Demand and Energy Forecasts

In PowerBase, projected future demand and energy growth rates are input at the company level. For EGEAS purposes, these growth rates must be aggregated up to the regional level for each of the MTEP16 futures. The MISO baseline value (M, in the futures matrix) for the demand growth rate is derived from the Module E 50/50 load forecast growth rate (0.8 percent). Low and high values, for both demand and energy, are achieved by modeling 1.3 standard deviations above and below the baseline. By utilizing the Load Forecast Uncertainty (LFU) metric, there is an 80% probability that the demand and energy forecast will fall within the high and low growth rates of 0.14% to 1.5%.

The effective demand and energy growth rates for each region are calculated after the EGEAS capacity expansion analysis, taking only state-level DSM mandate and goal projections into consideration. In MTEP15, MISO allowed EGEAS to pick additional DSM based on program economics. Without having more recently updated projections of future DSM potential (the Global Energy Partners study was completed in 2010), stakeholders expressed concern over the accuracy of continuing to model GEP-developed DSM estimates. Therefore, MISO only modeled enough DSM to meet state mandates and goals in the BAU, HD and LD scenarios. The CPP and SCPP scenarios include half of the energy efficiency growth based on the EPA's draft CPP proposal. The effective growth rates are ultimately used in the production cost modeling simulations (Table E2.4). In the same timeframe, MISO commissioned the Applied Energy Group (previously Global Energy Partners) to update the DSM study performed in 2010. This updated analysis was presented in specific workshops, in MTEP17 Futures development workshops and PAC meetings and is being implemented in the MTEP17 Futures.

	BAU		HD		LD		CPP		SCPP	
Region	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)
MISO	0.65%	0.76%	1.43%	1.53%	0.00%	0.11%	0.27%	0.46%	0.27%	0.46%
NYISO	-0.20%	-0.82%	0.71%	-0.70%	-1.04%	-1.03%	0.48%	-0.14%	0.48%	-0.14%
PJM	0.26%	0.45%	1.23%	1.40%	-0.44%	-0.25%	0.68%	0.79%	0.68%	0.79%
SERC	1.33%	1.20%	2.76%	2.36%	0.20%	0.28%	1.25%	1.13%	1.25%	1.13%
SPP	1.13%	1.42%	2.34%	2.79%	0.17%	0.33%	1.02%	1.33%	1.02%	1.33%
TVA	1.60%	0.78%	3.30%	1.53%	0.23%	0.18%	1.55%	0.77%	1.55%	0.77%

Table E2.1 E2.3: Effective demand and energy growth rates (2015-2030)

E2.2.3 Fuel Forecasts

Many of the fuel forecasts are developed in PowerBase using a pointer system. This makes it easier to make adjustments to the fuel forecasts without having to change each individual unit's forecast. A pointer system works by designating one fuel as the fuel index and then all other fuel forecasts are based on this fuel index, with some adjustment (usually due to transportation costs) from the index value. In the MTEP database, all natural gas-fired generators point to the Henry Hub natural gas forecast. Therefore, all references to natural gas in the futures matrix are in terms of the Henry Hub forecast.

For MTEP16, the source for the baseline natural gas forecast is the Phase III Natural Gas report developed for MISO by Bentek[1]. Since Bentek assumed an inflation rate of approximately 3.5 percent in their forecast, it was necessary to remove this inflation rate and to use the inflation rates for each future scenario that was identified by the PAC and MISO in the assumptions development process, with low and high inflation rates in other futures typically 2% and 4%. The five resulting MTEP16 natural gas forecasts are in nominal dollars per MMBtu (Figure E2.7).

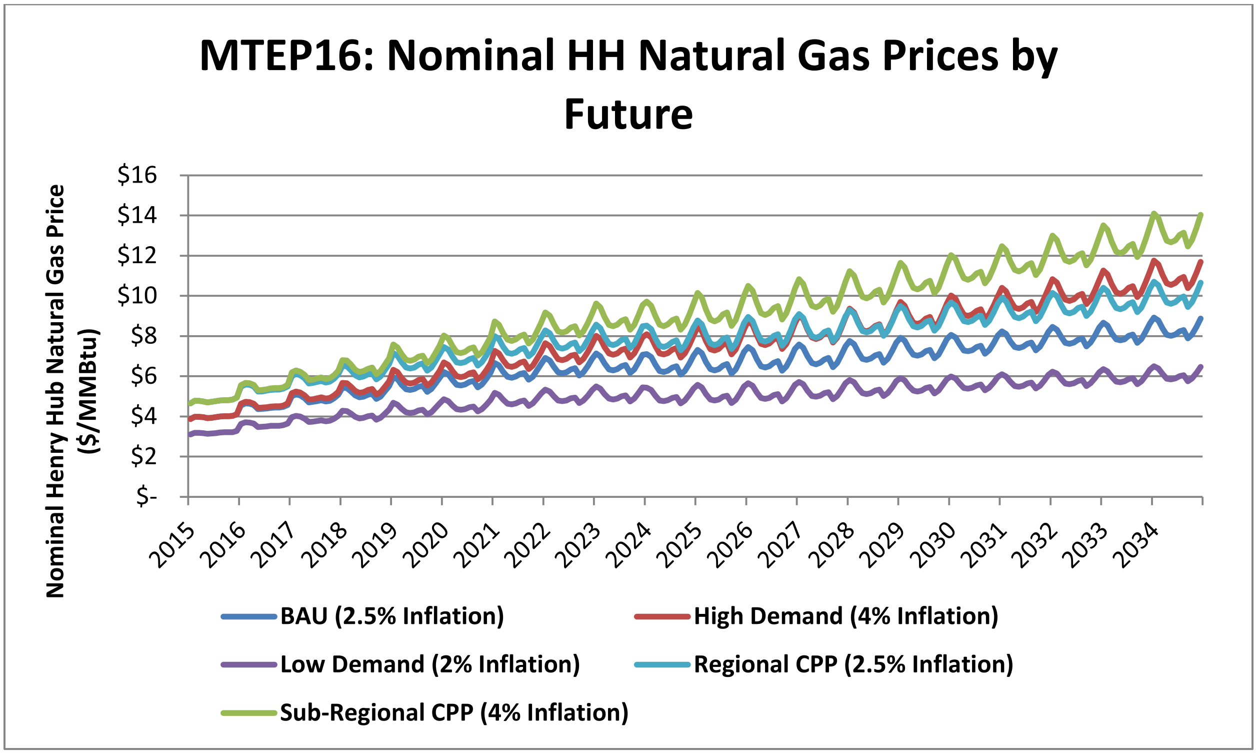

Figure E2.7: MTEP16 natural gas prices by future

E2.2.4 Study Period

The future outlook for MTEP EGEAS simulations is 20 years. The base year for MTEP16 modeling is 2015, extending out to 2034. In order to eliminate any "end effects" an extension period of 40 years is simulated, with no new units forecasted during this time. This additional study period ensures that the selection of generation in the last few years of the forecasting period (e.g. years 18, 19, 20) is based on the costs of generation spread out over the total tax/book life of the new resources (i.e. beyond year 20).

[1] Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis – An Analysis of Pipeline Capacity Availability.

E2.2.5 Study Areas

The MTEP16 database is comprised of all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada. The eight areas referenced in this appendix are:

- Midwest Reliability Organization (MRO)
- Midcontinent Independent Transmission System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM Interconnection (PJM)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Tennessee Valley Authority (TVA)

All other regions of the Eastern Interconnect, such as Manitoba Hydro and Independent Electricity System Operator (IESO) are deemed to have sufficient capacity resources in all MTEP scenarios and, as such, EGEAS capacity expansions are not needed for these regions. However, these regions are still modeled in the production cost modeling simulations. The TVA region has been modeled as two pools in an effort to more accurately model market behavior, which is constrained by TVA's ability to sell power only to certain companies. The three companies that comprise the "TVA-Other" pool - Associated Electric Cooperative, Louisville Gas & Electric and Kentucky Utilities - do not have such a restriction. The restricted sale phenomenon has been termed the "TVA Fence" and it is captured through PROMOD pool definitions and their associated settings.

E2.2.6 Capacity Types

Generation capacity is categorized into existing, under construction and planned units. Assumptions related to each of these categories include the following:

- Existing: Operating license extensions are assumed on all nuclear units.
- Under Construction: Units with steel in the ground, but not yet under commercial operation.
- Planned: All capacity resources with a signed Generator Interconnection Agreement (GIA).

E2.2.7 Firm Interchange

Firm interchange contributes to resource adequacy by reducing a region's overall internal capacity needs over time. It is assumed that each modeled region will build generation capacity to meet its own resource adequacy needs.

Based upon the 2015 Loss of Load Expectation (LOLE) External Ties Model, MISO assumes a net scheduled interchange of 3,157 MW. This capacity is held constant in all 20 years of the EGEAS modeling and is assumed to be available at the time of MISO peak.

E2.2.8 Planning Reserve Margin Targets

The Planning Reserve Margin (PRM) is entered into EGEAS for the first year of the simulation, and is assumed to remain constant throughout the entire 20-year study period. PRM targets are based on respective system co-incident peaks (MW), with the exception of SPP's, which is based on its non-coincident peak (MW). Table E2.5 presents the 2014 reserve margin, as well as the PRM target, for each region.

Region	2014 Reserve Margin (%)	PRM Target (%)
MISO	22.2	14.30
NYISO	27.0	17.00
PJM	19.3	15.60
SERC	28.5	15.00
SPP	34.9	13.60
TVA	29.1	15.00

Table E2.5: PRM margins and targets

E2.2.9 Wind Hourly Profile and Capacity Credits

A majority of the wind in the MISO footprint is registered as Dispatchable Intermittent Resources, or DIR. Generators with this designation are able to bid into the day-ahead market using high-confidence wind forecast data. Given that this information is not available for future years, EGEAS models all wind as a non-dispatchable technology using actual historical wind data developed during the MISO Regional Generator Outlet Study (RGOS). All the RGOS wind zone profiles within MISO are averaged to arrive at a single profile, which is used in the EGEAS capacity expansion analysis. Similarly, a single profile for each of the regions external to MISO is made by averaging all NREL wind sites within each respective region.

The wind capacity credit is the maximum capacity credit that a wind resource may receive if it meets all other obligations of Module E to be a capacity resource. This value, which is a percent of the maximum nameplate capacity of the unit, reflects the risk associated with reliance upon an intermittent resource, such as wind. The capacity factor is the actual annual energy output of the unit as a percentage of the total potential energy output (based on 8,760 hours in a year). The wind capacity credit is updated annually during the MISO Loss of Load Expectation (LOLE) analysis and, for the 2015 planning year, was calculated to be 14.7 percent. Table E2.6 shows the capacity factors applied to each region as input to the EGEAS model for MTEP16.

Region	Annual Capacity Factor (%)
MISO	40
NYISO	40
PJM	37
SERC	43
SPP	43
TVA	36

Table E2.6: Regional wind modeled capacity factors

E2.2.10 Reserve Contribution

Three specific assumptions were made with regard to reserve contribution:

- 14.7 percent of nameplate wind capacity is counted toward its reserve capacity contribution.
- 25 percent of nameplate solar capacity is counted toward its reserve capacity contribution in the non-CPP futures, and 40 percent of nameplate solar capacity is counted toward its reserve capacity contribution in the CPP futures based on the Minnesota Renewable Energy Integration and Transmission Study.[2]
- The summer de-rated capacity for conventional generation is counted toward its reserve capacity contribution.

E2.2.11 Financial Variables

Variables associated with the financing of new generation projects are listed in Table E2.7. Note that these are average values across the footprint. These financial variables are used in MTEP15 EGEAS simulations.

Variable	Rate (%)
Composite Tax Rate	39.00
Insurance Rate	0.50
Property Tax Rate	1.50
AFUDC* Rate	7.00

* Allowance for Funds Used During Construction

Table E2.7: Financial variables

[2] https://mn.gov/commerce/energy/images/final-mrits-report-2014.pdf

E2.2.12 Load Shapes

EGEAS requires a representative hourly load shape for the system as well as any technologies which are modeled as non-dispatchable. The shapes are provided in per unit values and, in the case of wind, solar and the overall system, are representative system averages across the footprint. The load shapes used in EGEAS simulations and their sources are presented in Table E2.8.

Load Shape	Description and Source
System	2006 hourly profiles from Ventyx, aggregated to regional level
Wind	2006 hourly profiles developed by AWS TrueWind for EWITS
Solar	2006 hourly profile developed by NREL for the Eastern Renewable Generation Integration Study (ERGIS) and used in the Minnesota Renewable Integration and Transmission Study (MRITS)
Energy Efficiency	Representative profile provided by Global Energy Partners, LLC as part of the 2010 Assessment of Demand Response and Energy Efficiency Potential for MISO.

Table E2.8: Load shape descriptions and sources

E2.2.13 Alternative Generator Categories

Table E2.9 and Table E2.10 list the generic categories of generators used when forecasting future units to meet the planning reserve margin requirements.

Supply Side Options
Biomass
Combined Cycle - with and without sequestration
Combustion Turbine
Compressed Air Energy Storage
Hydro
Integrated Gasification Combined Cycle (IGCC) - with and without sequestration
Nuclear
Pumped Hydro Storage
Solar
Wind - on-shore and off-shore

Table E2.9: Alternative generator categories – supply-side

Demand Side Options
Commercial & Industrial (C&I) Low Cost Energy Efficiency (EE) program
C&I Interruptible

Table E2.10: Demand-side management alternatives

E2.2.14 Renewable Maturity Cost Curves

Maturity curve costs are applied to the solar and wind resources to allow economic selection. The curves are shown in the graphs below. The maturity curve was developed by using publicly available information from various reports and documents to establish the assumptions behind what drives the cost down for renewables and the magnitude of reduction in costs that would occur.

The starting value for solar is based on capital costs information from Lazard's annual report on levelized costs of energy. The curve declines at a rate of 10% per year for five years per assumptions in the Annual Energy Outlook 2014 Assumptions Report.[3]

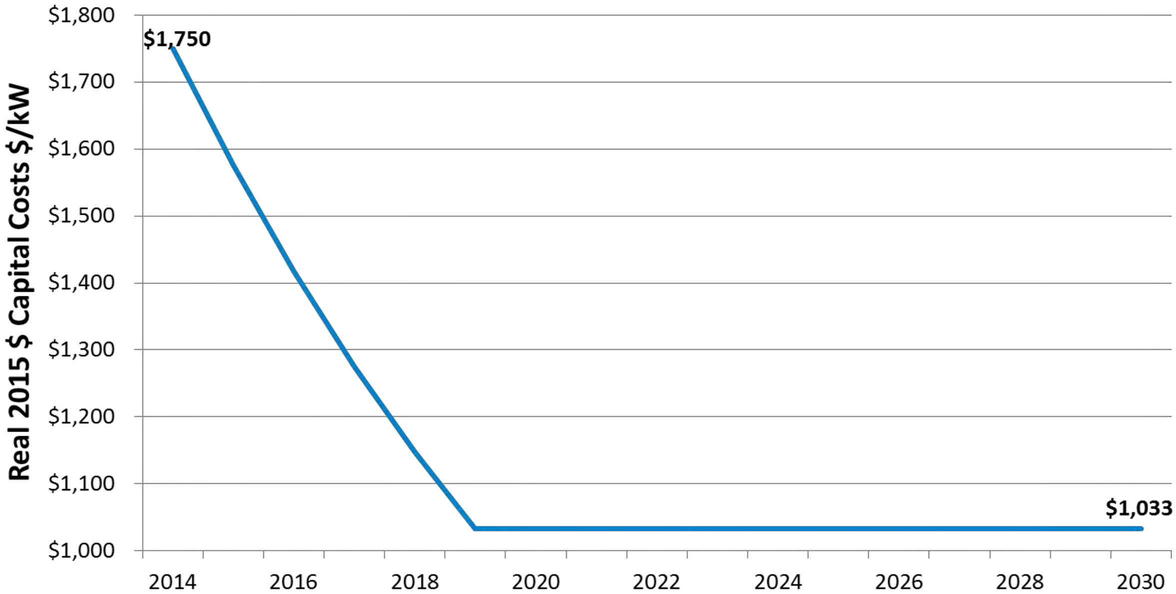

Figure E2.8: Solar Maturity Curve

[3] Starting cost taken from Lazard 2014 LCOE Report: Page 11
http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf
Estimated cost decline taken from EIA AEO 2014 Assumptions Report: Page 98
http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf

The starting capital costs for wind are based on information from the DOE LBNL 2013 Wind Technologies Market Report. The curve declines at a rate 1% per year for five years; assumptions based on the Annual Energy Outlook 2014 Assumptions Report.[4]

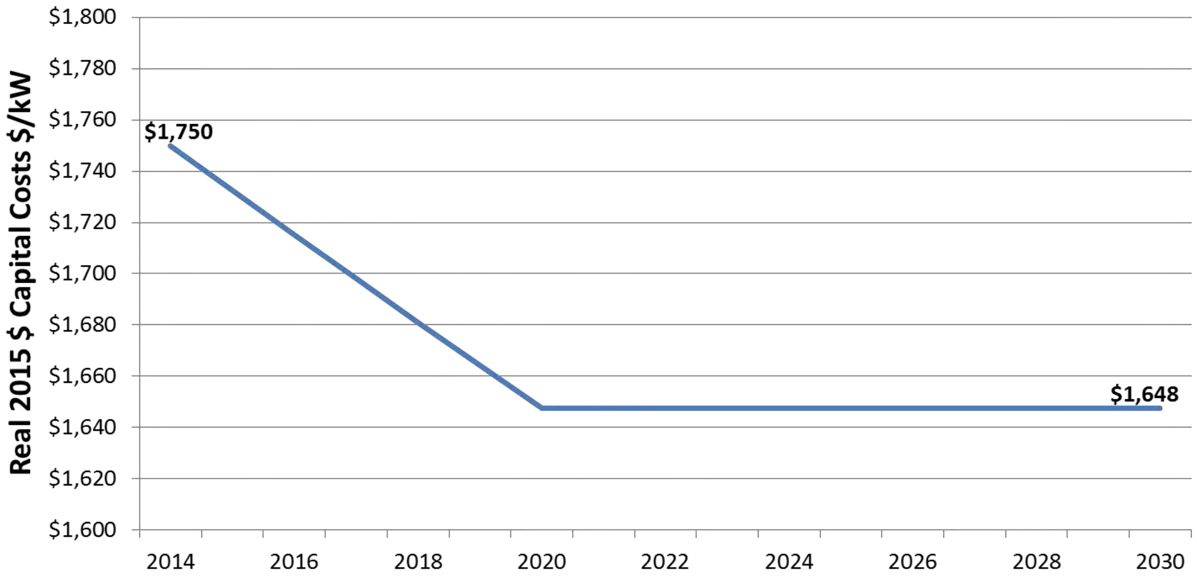

Figure E2.9: Wind Maturity Curve

E2.2.15 Alternative Generator Data

Table E2.11 shows the fixed operation and maintenance (O&M) cost, variable O&M cost, heat rate, lead time (inclusive timeframe for unit construction), maintenance hours, and forced outage rate (FOR) for the alternative supply-side generator categories used in MTEP16 regional resource forecasting. The capacity of each forecasted generic unit from each category is 1,200 MW, with the exception of wind at 300 MW. Monetary values given in the table are in 2015 dollars.

Type	Fixed O&M	Variable O&M	Heat Rate	Lead Time	Maintenance Schedule	Forced Outage Rate
	$/kW-Yr.	$/MWh	MMBtu/MWh	Years	Hours	%
Biomass	105.63	5.26	13.50	4	0	3.25

[4] Starting cost taken from DOE LBNL 2013 Wind Technologies Market Report: Page 50
http://energy.gov/sites/prod/files/2014/08/f18/2013%20Wind%20Technologies%20Market%20Report_1.pdf
Estimated cost decline taken from EIA AEO 2014 Assumptions Report: Page 98
http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf

CC	10.13	1.59	6.43	3	336	5.11
CCS*	47.98	3.31	7.53	3	504	5.11
CT	8.7	2.46	9.75	2	168	5.93
Hydro	14.13	2.66	0.00	4	0	3.25
IGCC	55.05	6.66	8.70	6	672	5.11
IGCCS**	34.06	7.79	10.70	6	672	5.11
Nuclear	68.7	2.49	10.40	11	672	2.95
PV	21.75	5.00	0	2	0	0
Wind	39.55	5.00	0	2	0	0

* Combined-Cycle with Sequestration
** Integrated Gasification Combined-Cycle with Sequestration

Table E2.11: Alternative generator data

E2.3 Results of Regional Resource Forecasting

The conditions modeled in each future scenario result in various forecasted levels of resource additions and retirements which are shown in the figure below. The non-CPP futures show that levels of resources added are a direct correlation to the demand and energy growth assumptions. In addition, there is a greater selection of CTs over CCs in the non-CPP futures because the additional resources are required to meet the reserve capacity needs of the system as opposed to the energy needs which are met through renewables and DR/EE.

In the CPP cases, the model shows a buildout of more CCs with the main driver being the carbon cost only applied to existing units in accordance with the proposed 111(d) rule. Additionally, economic renewable selection is driven by the carbon cost on the system and the increased retirements from age-related units and coal. In Regional CPP case, solar makes up a majority of the renewable while in the SubRegional CPP case it's split between solar and wind. The primary driver of that spilt is the increased carbon cost applied to the SCPP future.

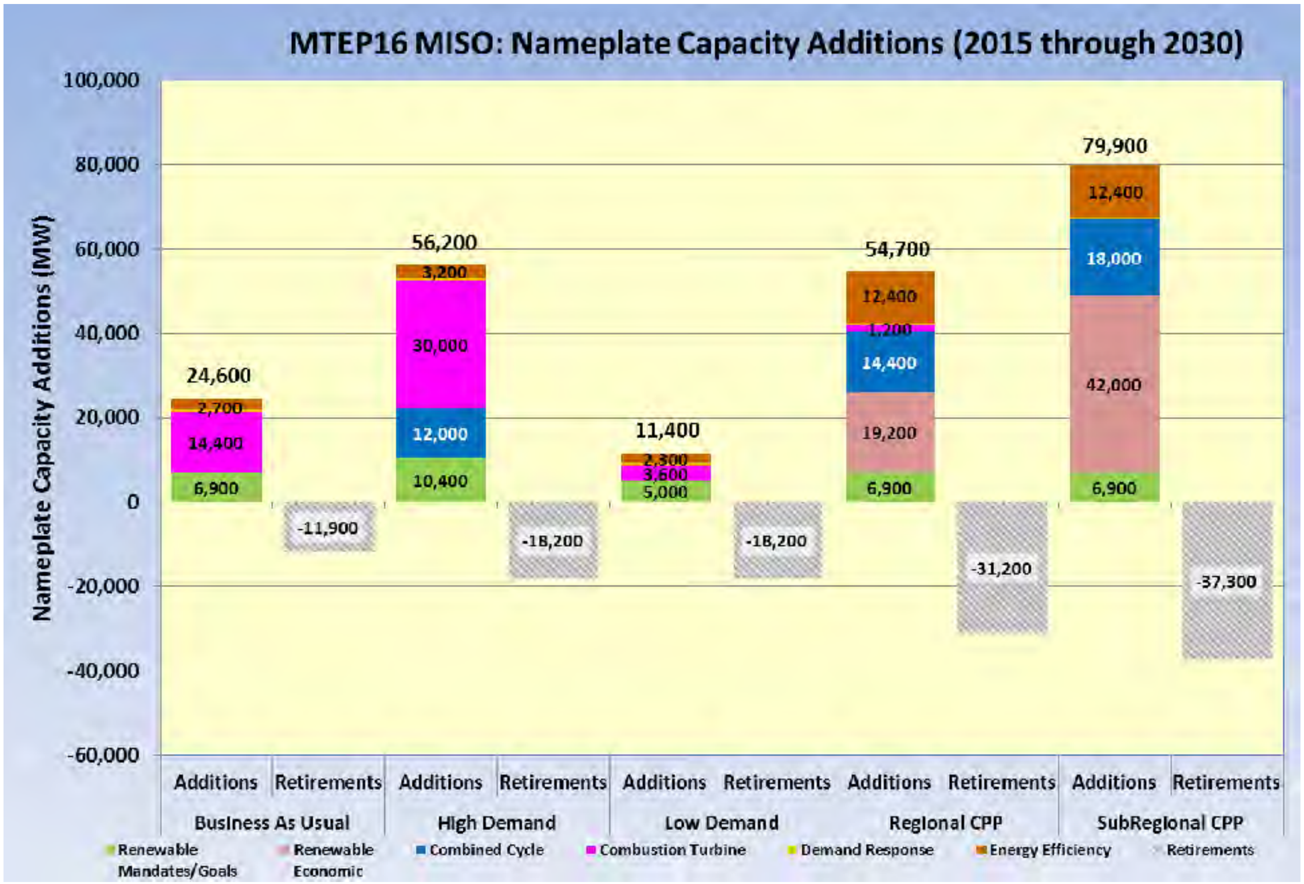

Figure E2.10: Resource Additions and Retirements

The energy usage of the system is shown for each future in the chart below. The chart shows the energy utilization of the system in the year 2015 compared to year 2030. For the non-CPP futures, coal is dispatched at 60% in the base year while coal is dispatched at 64% in the CPP futures. The driver for the difference in base year energy utilization is the starting natural gas price. The higher gas price makes more coal resources get dispatched over gas resources.

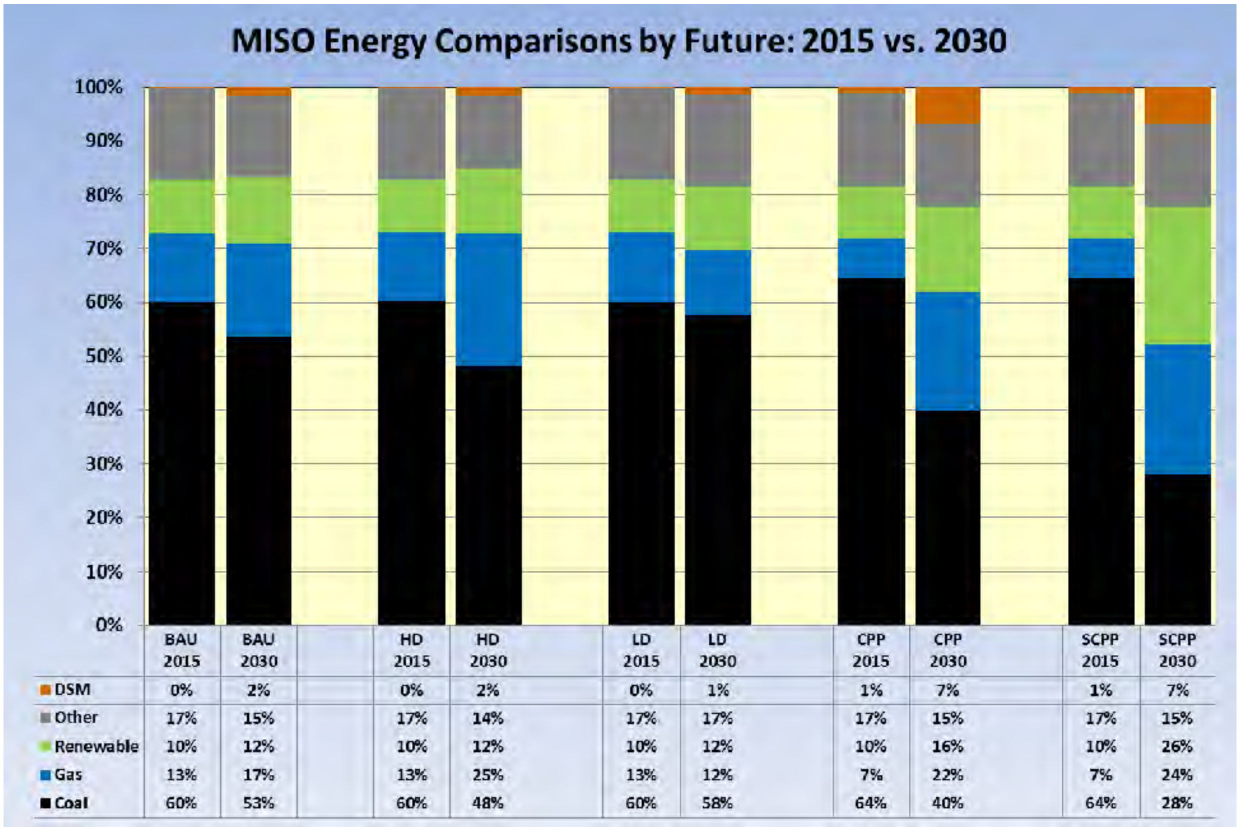

Figure E2.11: Energy Utilization by Resource

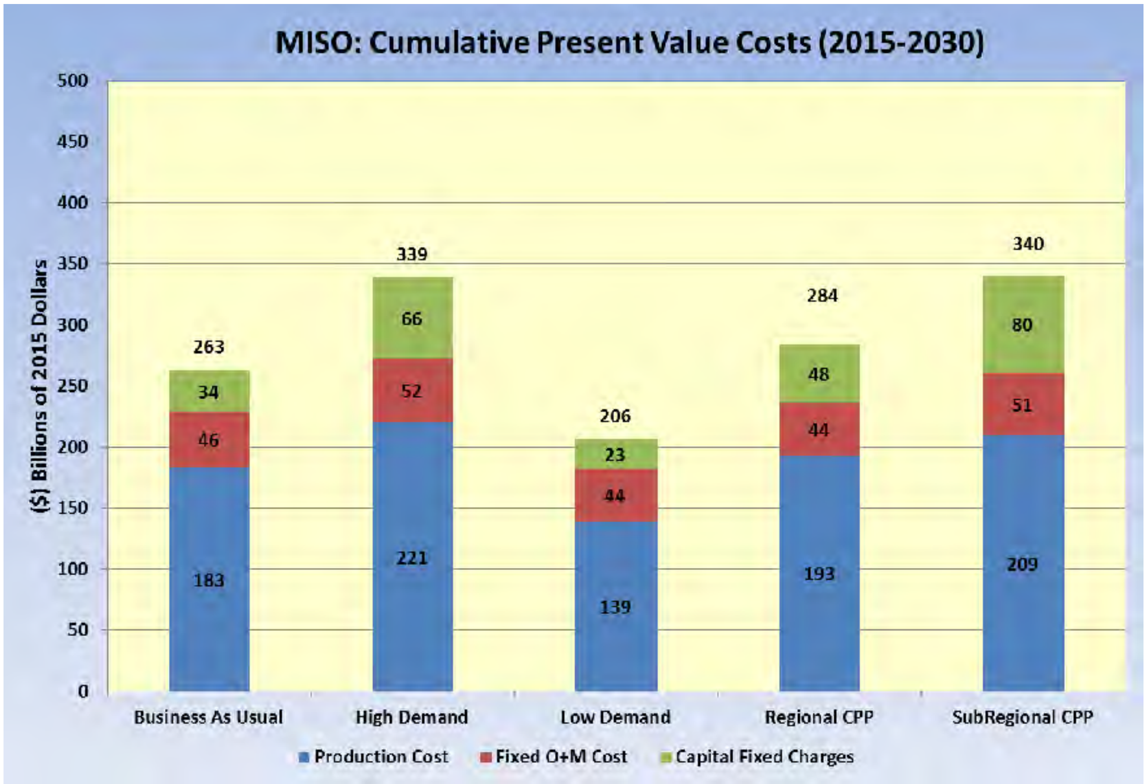

Figure E2.12: Present Value Costs

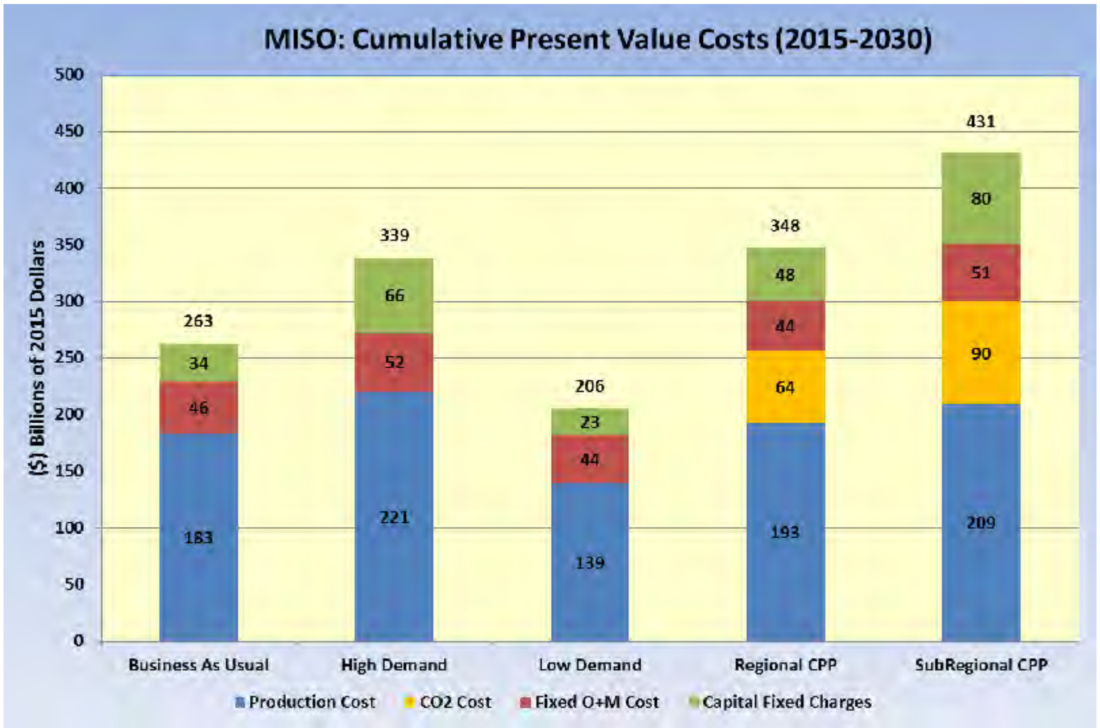

Figure E2.13: Present Value Costs with Carbon Cost

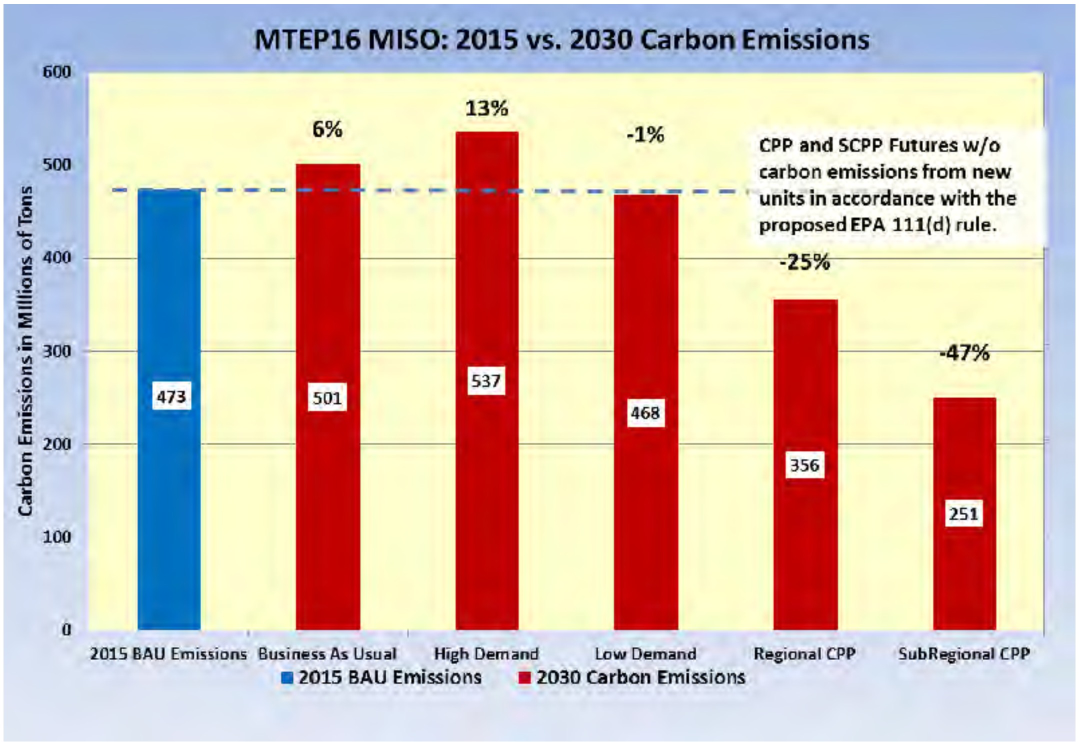

Figure E2.14: Carbon Emissions with only Existing Units

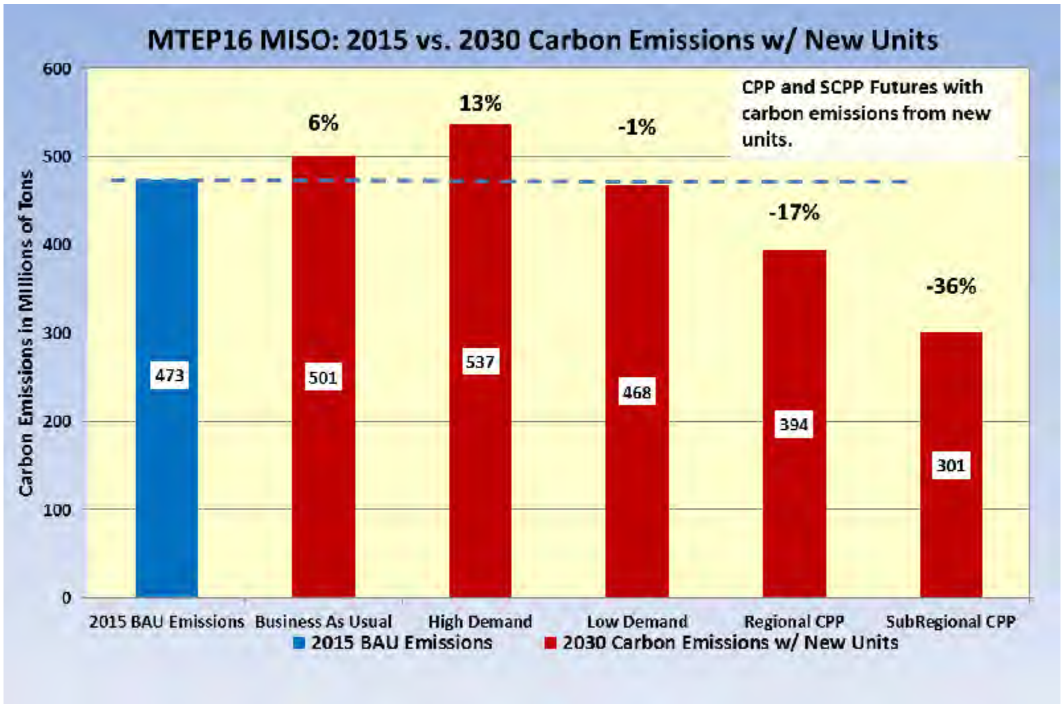

Figure E2.15: Carbon Emissions with New Units

E2.4 Siting of Regional Resource Forecasted Units

Regional Resource Forecasted (RRF) units result after applying the Futures conditions to the system (load growth, fuel and capacity costs, renewable portfolio standards, emissions costs or constraints, etc.) and evaluating what resource mix is the most efficient going forward. Given that the generator interconnection queue is typically only useful for one to five years out for capacity, a capacity expansion tool, such as EGEAS, is used to supplement the out years to maintain the load-to-resource balance. These units must be sited within the powerflow model for use within the production costing models. Beginning with MTEP11, MISO included Demand Response (DR) and Energy Efficiency (EE) units in the EGEAS capacity planning process. While EE is simply netted out of the baseline demand and energy values, DR units also have to be sited into the powerflow models for production cost analysis. Therefore, additional siting methodology for DR has been developed. A Geographic Information System (GIS) software program called MapInfo is used to assist in the generation siting. Siting rules, which are detailed below, are used to develop layers within the mapping software showing the potential locations of the resource forecasted units.

The siting can be broken into four main categories. The categories are general siting rules, future-specific siting rules, siting priority order and, finally, unit-specific greenfield siting. General siting rules apply to all futures, while future-specific siting rules only apply to certain futures (i.e. only use queue units as possible sites). Siting priority sets what sites will be looked at first and then finally how each technology will be sited for greenfield. The overall siting process is being revised as a part of the MTEP17 process, developing additional criteria for thermal fleet siting and additional wind & solar specific zones.

E2.4.1 General Siting Rules

The rules outlined in this section show, at a higher level, many of the underlying assumptions that go into the siting of RRF generation. These criteria could be referred to as the "first pass" siting criteria.

- Site by region, with the exception of wind.
- "Share the Pain" mentality. Not all generation in a region can be placed in one state and one state cannot be excluded from having generation sited.
- Avoid greenfield sites for gas units (CTs and CCs) if possible - prefer to use all brownfield sites.
- Site baseload units in 600 MW increments, except nuclear which is sited at 1,200 MW.
- Limit the total amount of expansion at an existing site to no more than an additional 2,400 MW.
- Restrict greenfield sites to a total size of 2,400 MW.
- Limit using queue generation in multiple futures.
- Transmission is not an initial siting factor, but may be used as a weighting factor, all things being equal.

E2.4.1.1 Generator Developmental Statuses

A generator's developmental status is required to determine how the unit will be treated in both the EGEAS capacity expansion model and the siting process. Existing and queue generation is given one of the following developmental statuses within the PowerBase database:

- Active – Existing, online generation including committed and uncommitted units. Does not include generation which has been mothballed or decommissioned.
- Planned - A generator that is not online, has a future in-service date, is not suspended or postponed and has proceeded to a point where construction is almost certain, such as it has a signed Interconnection Agreement (IA), all permits have been approved, all study work has been completed, state or administrative law judge has approved, etc.
  - These units are used in the model to meet future demand requirements prior to the economic expansions.

- Future – Generators with a future online date that do not meet the criteria of the “planned” status. Generators with a future status are typically under one of the following categories, proposed, feasibility studies, permits applied, etc.
  - These generators are not used in the models but are considered in the siting of future generation.
- Canceled – Generators that have been suspended canceled, retired or mothballed. These units are not included in the EGEAS capacity expansion model, although their sites are often considered for brownfield locations in the siting process.

E2.4.2 Future-Specific Siting Rules

In an effort to produce capacity expansions that capture a wide range of future possibilities, certain criterion may be applied to one scenario that are not applied to others. Here are some examples of future-specific siting criteria:

- For one future, use non-signed IA queue generators as possible locations, but don’t reuse in other futures
- Use all brownfield/expandable sites in a future, if possible
- Use brownfield sites early, then greenfield sites
- Use a “smart” siting methodology in one future, i.e. “energy park” mentality
  - Site CT near Wind if other criteria are met
  - Site CT, CC, Coal and Wind near each other if all criteria are met

E2.4.3 Site Selection Priority Order

- Priority 1: Generators with a “future” status
  - Queue generators without a signed IA
  - The “New Entrants” Generators defined by Ventyx (noted as “EV” Gens)
  - Both Queue and EV Gens are under the following statuses:
    - Permitted
    - Feasibility
    - Proposed
- Priority 2: Brownfield sites (Coal, CT, CC, Nuclear Methodology)
- Priority 3: Retired/mothballed sites that have not been re-used
- Priority 4: Greenfield sites
  - Queue and “New Entrants” in canceled or postponed status
- Priority 5: Greenfield sites
  - Greenfield siting methodology

E2.4.4 Unit-Specific Greenfield Siting Rules

Thermal unit siting uses a specific set of rules for each type of capacity.

E2.4.4.1 Greenfield Combined-Cycle Siting Rules

Required Criteria:

- Within 1 mile of railroad or navigable waterway
- Within 2 miles of river or a lake (lake has to be larger than 100 mi2)
- Within 10 miles of a gas pipeline (diameter of 12 inches or greater)
- Within 25 miles of a major urban area

E2.4.4.2 Greenfield Combustion Turbine Siting Rules

Required Criteria:

- Within 20 miles of railroad or navigable waterway
- Within 5 miles of a gas pipeline (diameter 12 inches or greater)

Optional Criteria:

- CT’s can almost be located anywhere
- CT’s historically have been located near metro areas, but not required
- CT’s do not need a river for cooling
- Less likely to build pipeline for CT vs. CC
- CT’s may be the preferred generation for coal retirement sites within metro areas

E2.4.4.3 Greenfield Nuclear Siting Rules

Required Criteria:

- Use existing nuclear sites only
- All states are eligible for siting of future nuclear generation

E2.4.4.4 Greenfield Wind Siting Rules

Required Criteria:

- Not in a state or national park
- Not in metro areas
- Not on state-managed lands
- Site wind within a state to meet its mandate, unless potential wind capacity is exceeded, then site in neighboring state(s)

E2.4.4.5 Greenfield Photovoltaic Siting Rules

Photovoltaic (PV) is sited using Solar Global Horizontal Irradiance Annual KWh per panel. The Solar Global Horizontal Irradiance Intelligent Map Layer includes monthly and annual solar resource potential for the United States. The insolation values represent the average solar energy available to a horizontal flat plate collector such as a PV panel. In addition to irradiance, proximity to high-voltage buses and a balance of urban & rural sites were used to attempt to capture the urban solar garden trend and to mimic distributed solar.

E2.4.4.6 Demand Response and Energy Efficiency Siting Rules

Demand response capacity is sited at the top five load buses in each LSE. If an LSE serves load in more than one state, the top five load buses in each state having a DR mandate or goal are used, with the DR being allocated based upon the percentage required in each state’s mandate or goal.

The impact of energy efficiency is accounted for in the demand and energy growth rates, as EE is typically available during all 8,760 hours in a year.

E2.4.5 RRF Unit Siting Maps

Figures E2-16 to E2-20 are an overview of the Regional Resource Forecast (RRF) unit siting for each of the future scenarios.

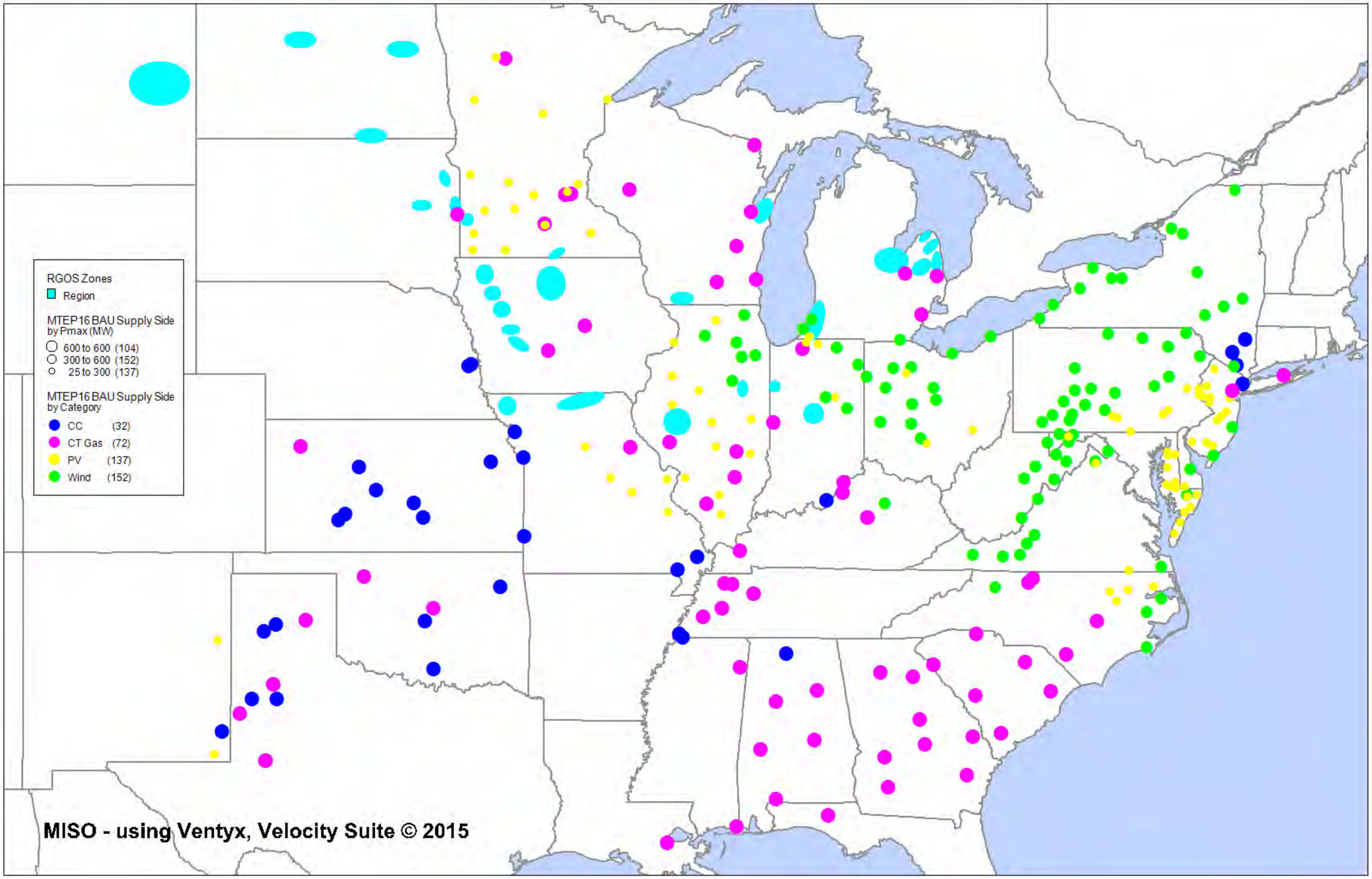

Figure E2.7: MTEP16 Business as Usual future generation siting map

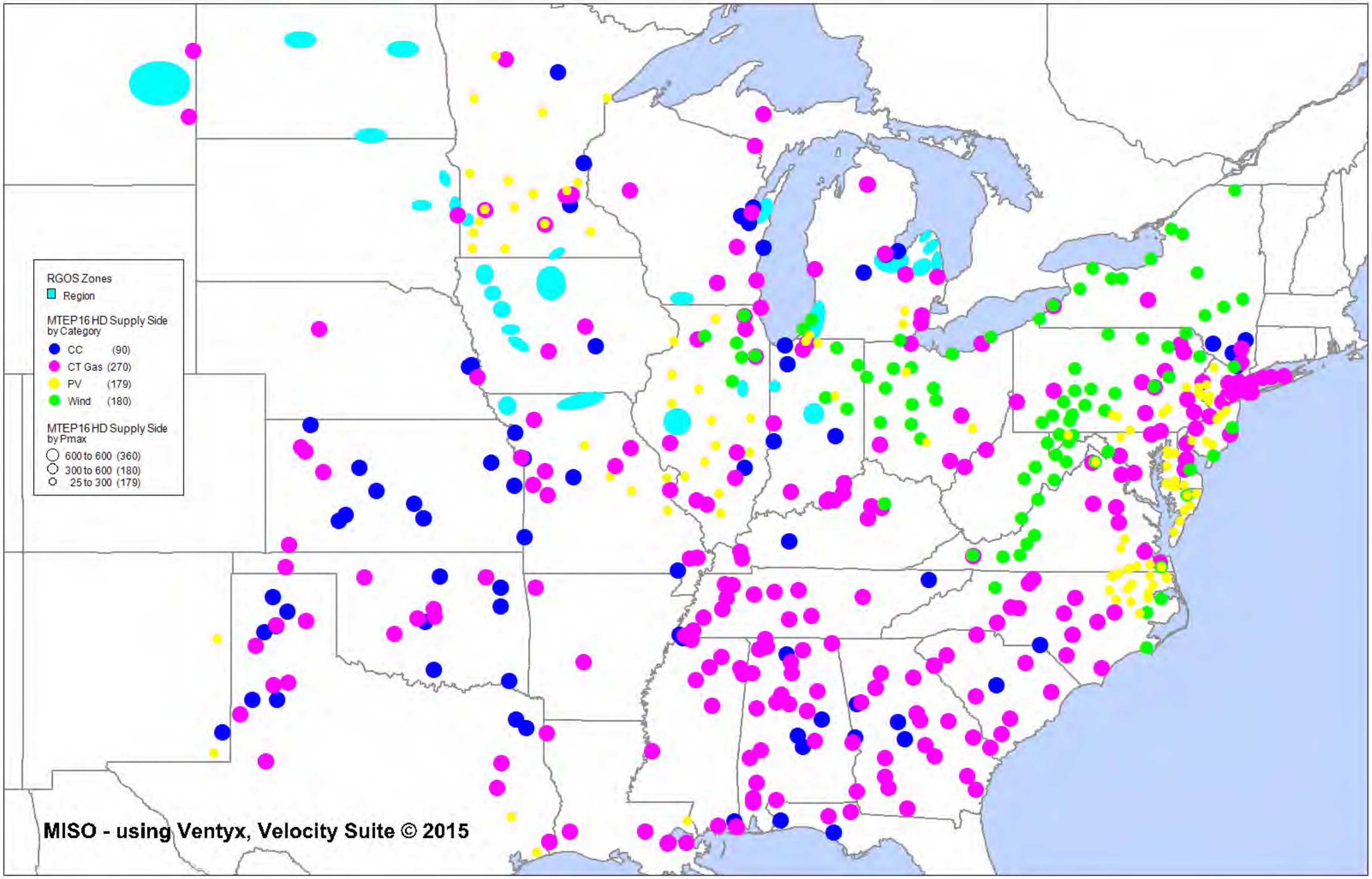

Figure E2.8: MTEP16 High Demand supply-side resource siting map

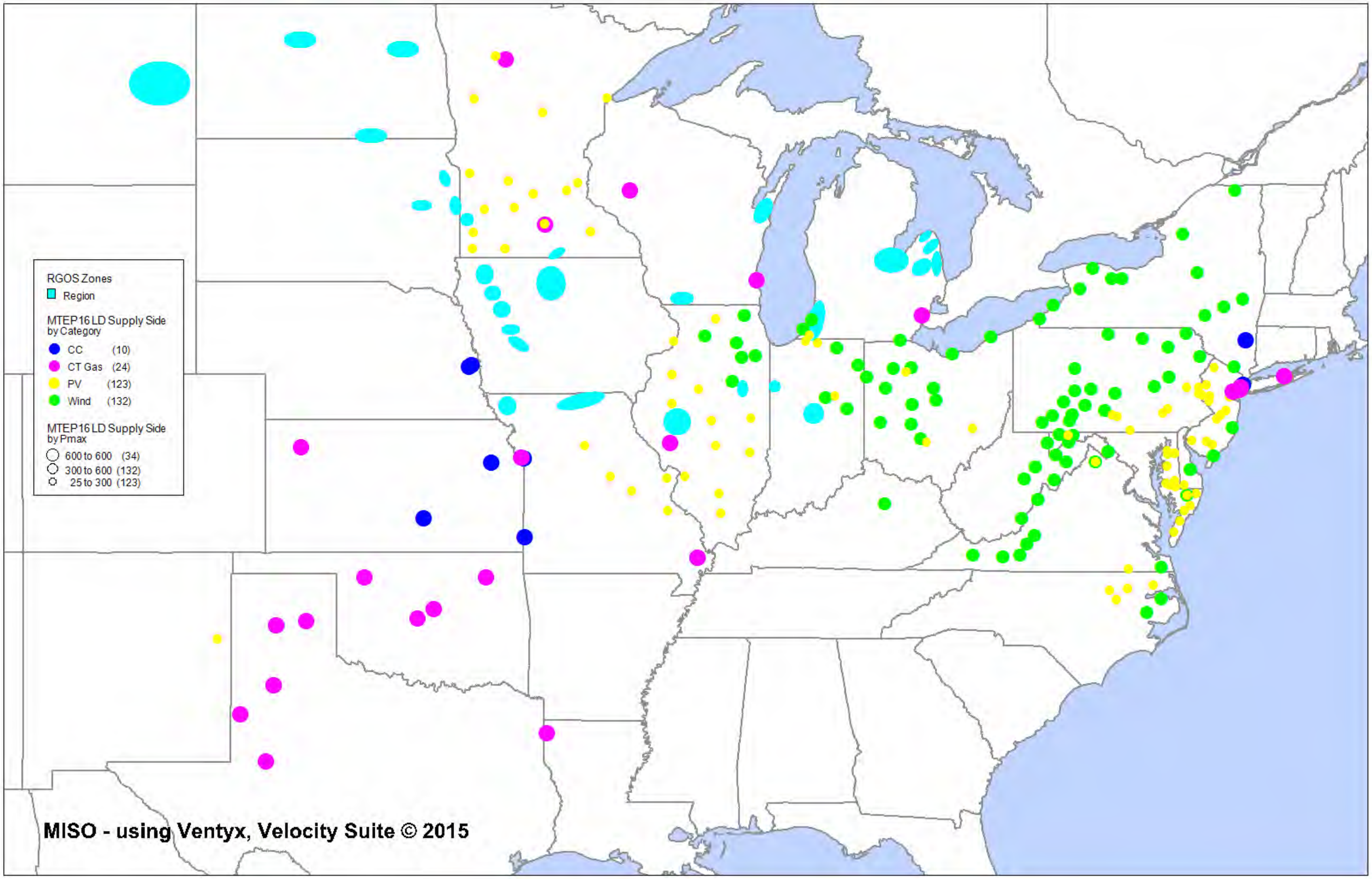

Figure E2.18: MTEP16 Limited Demand supply-side resource siting map

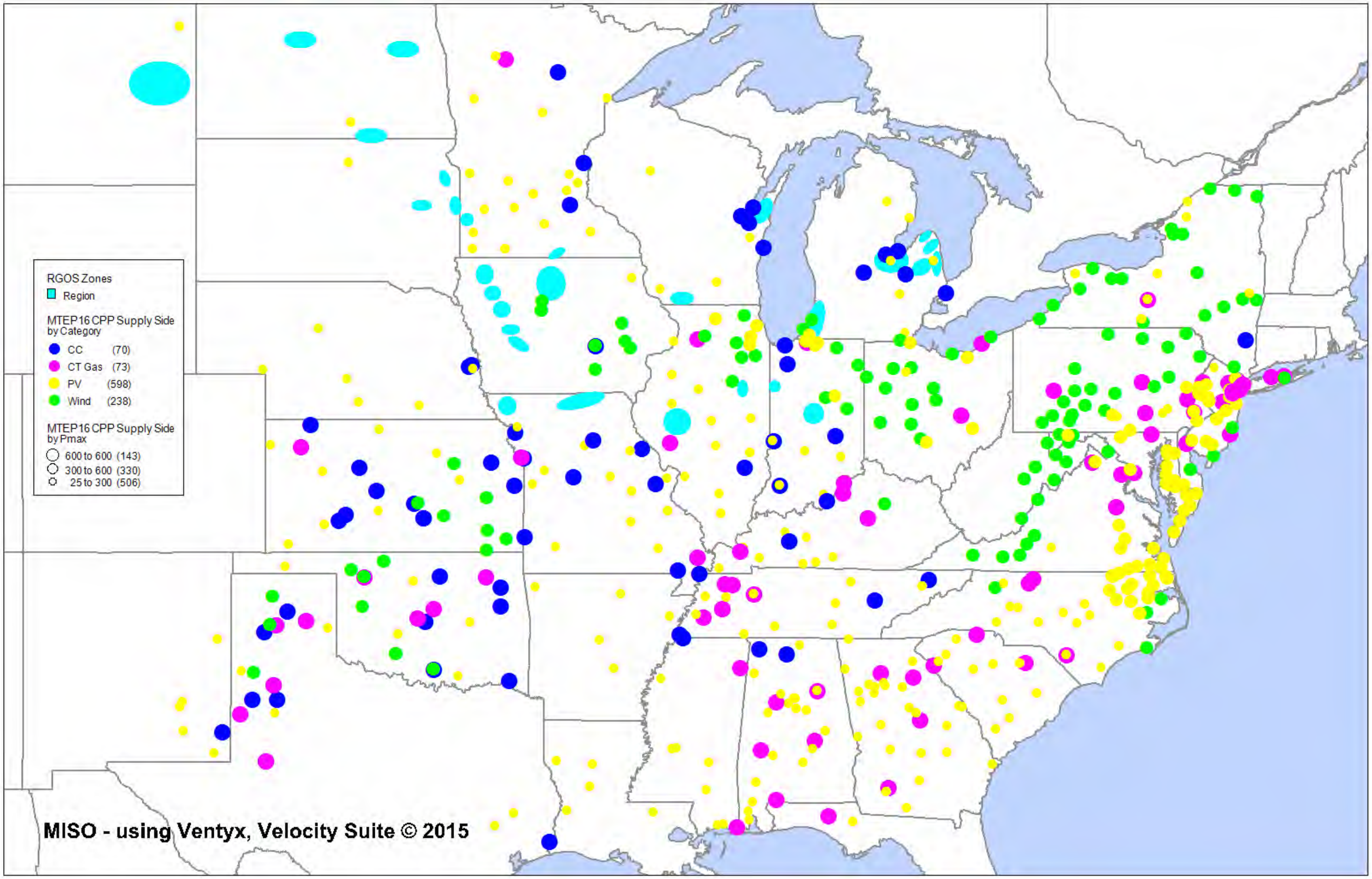

Figure E2.19: MTEP16 Clean Power Plan supply-side resource siting map

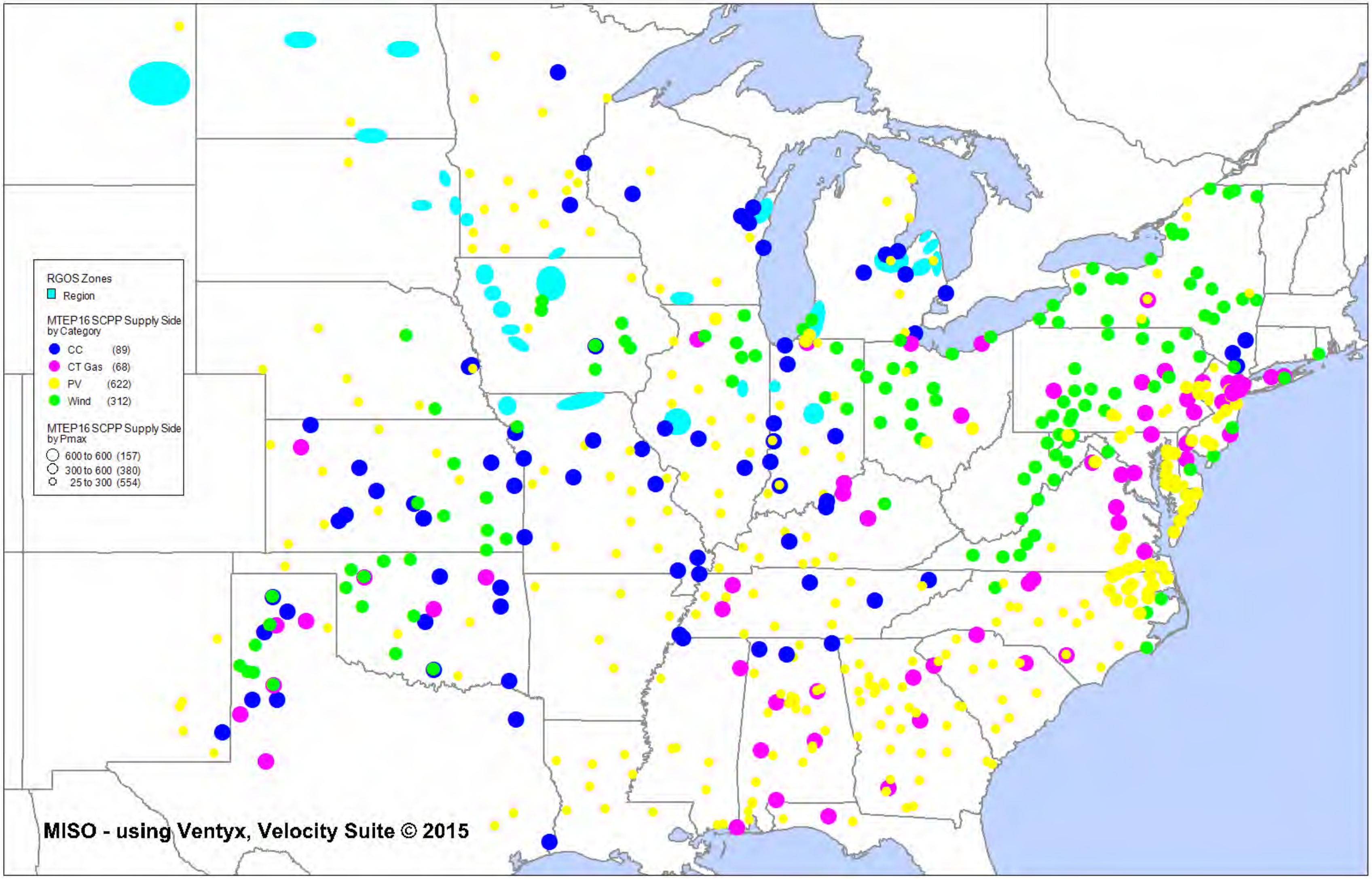

Figure E2.9: MTEP16 Subregional Clean Power Plan supply-side resource siting map

E2.4.6 Demand Response Siting

For MTEP16, demand response requirements for the Business as Usual, High Demand, and Limited Demand scenarios were calculated based only on the expected amounts needed to meet state mandates and goals. The resulting demand response is then sited at the top five to ten load buses in each LSE within the state having the mandate.